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SYSTEMS EVALUATION OF REFUSE AS A LOW SULFUR FUEL

A FINAL REPORT TO THE

ENVIRONMENTAL PROTECTION AGENCY

VOLUME II

REPORT NO. F-1295 NOVEMBER 1971

FOSTER WHEELER CORPORATION

Cottrell Environmental Systems
A Division of Research-Cottrell

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AS A LOW SULFUR FUEL

VOLUME II - APPENDICES

A Report to

ENVIRONMENTAL PROTECTION AGENCY

CONTRACT CPA 22-69-22

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APPENDIX A

WASTAGE AND FOULING

I. LITERATURE SURVEY

A. INTRODUCTION

An extensive survey was made of the literature to establish the background necessary to evaluate the ash deposit-corrosion problem in refuse-fired steam generators and to supplement the information generated in the laboratory and the data gathered through field interviews. A total of 33 articles directly related to the subject matter were reviewed, with about half of these articles being translated from the German. A large number of articles indirectly related to the subject were also reviewed to provide background in specific areas such as corrosion due to complex alkali sulfates, lead oxide, etc.

In reporting the results, the German workers have dealt primarily with theories explaining the mechanism of corrosion through chemical models. Unfortunately, they have minimized the importance of reporting the circumstances under which the deposits formed or corrosion took place, and therefore the chemical models remain largely unconfirmed. Only recently has work of any merit been reported on laboratory investigations made to support existing theories or explain field results (Ref. A-1). The lack of data may be illustrated by the tabulation of chemical analysis of deposits appearing in Table A-1, the data representing the entire sum of analyses reported in the thirty-three papers.

The conditions under which the corrosion and deposits occur are first reviewed and this is followed by a review of the mechanisms proposed in addition to a summary of the results.

B. OPERATING CONDITIONS

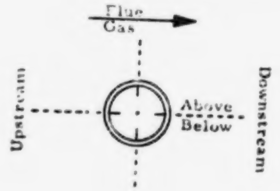
The literature reviews in varying extent the corrosion problems in approximately 11 different installations representing a variety of operating conditions and boiler designs. The operating data relevant to the corrosion or ash deposit problem have been tabulated for each plant in Table A-2 and it is apparent that there is no single contributing factor to corrosion. A number of factors, such as type of refuse, operating temperature, or individual details in design, all influence metal wastage. In some cases there appear to be conflicting data.

Corrosion in general is reported to occur on the upstream (leading) edges of superheater tubes in the first few rows of the tube bundle beneath deposits that are not porcelainized, and where the tube metal temperatures exceed 850°F. In some cases, the lowest temperature limit one might expect

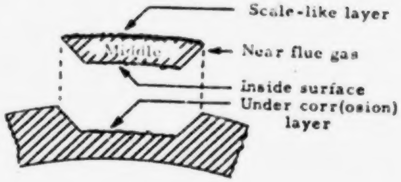
TABLE A-1 - CHEMICAL ANALYSES OF REFUSE-FIRED FURNACE DEPOSITS

Constituent	Ref. A-2			Ref. A-4(1)				Ref. A-5(2)										
				Upstream		Downstream		Scale-Like Layer		Under Corr. Layer		Inside Surface		Middle		Near Flue Gas		
	W.S.F.(3)	W.I.F.(4)	Ref. A-3	Above	Below	Above	Below	W.S.F.	W.I.F.	W.S.F.	W.I.F.	W.S.F.	W.I.F.	W.S.F.	W.I.F.	W.S.F.	W.I.F.	Ref. A-
Na_2O	3.84		3.6	3.12	4.87	5.00	11.75		1.0	3.9	3.9	3.4		3.9		3.6		
K_2O	6.20		11.5	3.31	5.12	2.56	6.75		3.6	0.7	19.2	16.9		12.7		7.9		14-24
CaO	5.40		16.4	1.85	2.45	-	1.50		0.7	7.2	9.8	2.0		4.5		5.7		10-20
Fe_2O_3	1.45	4.80	15.4	56.7	24.8	63.8	17.6	Tr.	75.5	Tr.	18.0	0.8	9.2	1.2	5.2	1.2	4.4	1-13
Al_2O_3	1.53	9.40	7.4	8.9	11.5	-	8.6		2.2	2.1								3-16
MgO	1.50		4.0							0.2	1.5		9.8		7.7		5.3	0.5-4.0
P_2O_5									0.3		1.1		0.6		0.9		1.4	
ZnO	4.75																	
SO_3	15.60	4.84	29.4	0.14	0.25	0.18	0.25		4.1	31.6	32.1	16.2	6.0	25.8	4.8	23.4	3.7	30-48
CO_2	11.60																	
Cl				6.4	5.5	6.1	4.8	4.3		Tr.		6.0						0.1-0.4
TiO_2		0.90																
SiO_2		11.90	8.5	2.51	3.21	0.81	2.57		0.9									4-14
PbO		14.00							0.6	5.1		5.5	21.1	5.0	19.8	4.0	21.5	
SO_4				12.85	28.38	11.75	37.80											
S				4.30	9.50	4.05	12.75											
pH			5.3	3.9	4.7	4.1	4.0											
% Water Solubles			45.4	17.4	35.1	15.4	45.8											

Designation of boiler tube deposit location:


Flue Gas
Upstream
Above
Below
Downstream

(2) Designation of removed deposit section.


Scale-like layer
Middle
Near flue gas
Inside surface
Under corr(osion) layer

(3) Water soluble fraction

(4) Water insoluble fraction

TABLE A-2

SUMMARY OF OPERATING CONDITIONS OF STEAM-PRODUCING INCINERATOR PLANTS

Plant	Pressure, psig	Temp, °F	Stoker	% Excess Air
Stuttgart	1135	975	Roller Grate	-
Munich	3000	985	Backward Feed Reciprocating Grate	80
Düsseldorf	1314	932	Roller Grate	100
Rosenheim	Sat. Steam	205	Roller Grate	-
Mannheim	1950	932	Traveling Grate	-
BASF	426	572	Von Roll Grate	-
Rotterdam	516	800	Martin Grate	60
Essen-Karnap	1470	932	Traveling Grate	-
Issy-les-Moulineaux	880	770	Reverse Reciprocating	100
Oceanside	460	462	Rocking	128
Norfolk	300	420	Detroit Reciprocating	50

to find corrosion was set between 930°F and 950°F. The variation may be due to a difference in composition of deposits. To a lesser extent it may be due to the procedure used for estimating tube metal surface temperature. In the Munich plant, there were a few isolated cases in which corrosion was reported on the bare side or the downstream side of the tube surface. Figure A-1 illustrates the locations in which corrosion has been reported in most cases.

Corrosion in the superheater banks is reported to occur at a catastrophic rate at first and then gradually subside as the ash accumulation increases. After 500 hours, metal loss of 0.0047 in. was measured, and 0.0078, 0.013, and 0.016 in. after 1000, 3000, and 5000 hours respectively (Ref. A-7). In numerous cases the deposits accumulated in this zone are reported to contain quantities of H_2S and release a strong odor upon heating or crushing.

One investigation (Ref. A-8) indicated the corrosion rate "becomes less when the percentage of ash content in the waste fuel increases" (in winter, i. e.).

Most investigations have attributed corrosion in these zones to complex alkali iron sulfates, and hydrochloric acid resulting from the burning of polyvinyl chloride. Typical of information available in this area, it is reported that the plant with the highest HCl content in the flue gas reports no corrosion damage at all, and the SO_2 content of the flue gas in refuse incinerators is reported to be below the level essential to support the formation of the complex alkali iron sulfates.

Huch (Ref. A-5) indicates the deposits are not typical of those usually associated with sulfate-type corrosion from either the complex alkali iron sulfates or the pyrosulfates, even though he reports a positive identification of the former in a deposit removed from a tube. "Sulfide formation could not be detected. For salt glaze corrosion, the tube walls with their temperature at about 662°F were at too low a temperature compared with the fusion and sintering temperatures of the coating on them, which were found to be 2192°F and 725°F, respectively. Areas of partial fusion that were observed were never found on the tube wall, but only in such places where the heat flow to the cooling tube had been retarded by cavities in the coating, or where the distance from the tube wall was already fairly large so that the temperature compared to the tube wall was already much higher."

Nowak (Ref. A-9) reports more than one type of corrosion appearing in the superheated banks. The second type he attributes to vanadium in the oil fired with the refuse in the Stuttgart plant. Flame photometric tests identified the presence of traces of vanadium in deposits.

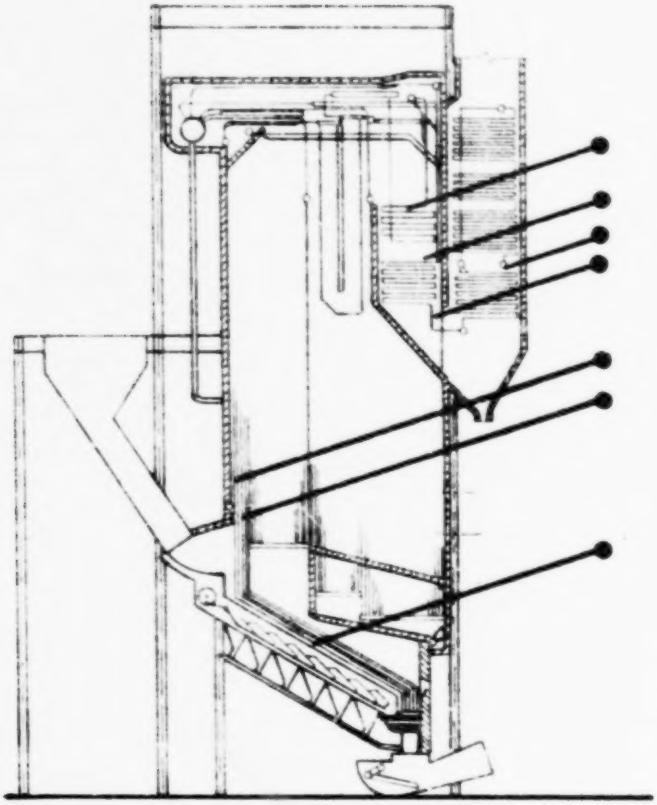


FIGURE A-1. TYPICAL LOCATION OF CORROSION IN LARGE STEAM-GENERATING INCINERATORS

Corrosion appears to occur despite the types of fuel used; i.e., refuse only, refuse and oil, or refuse and coal. In one plant, in which no corrosion has been reported (Essen-Karnap), the relative location at which the two fuels are burned has been considered a contributing factor to the reduction in corrosion. There are several other factors that must be considered in this case which will become more apparently shortly; (1) the combustion process is complete, assuring the elimination of a reducing atmosphere, and (2) all metallic material is removed prior to burning the refuse.

A second type of "corrosion" has been reported in the convection passes. It occurs at low gas temperatures and is prevalent around tube hangars and areas where gas passages take a change in direction. This is actually not corrosion, but erosion due to the high gas loading of large particulate material. Nowak (Ref. A-7) reports that "during the winter months especially high dust loadings of 8 to 10 g/m^3 were noticed, and in some cases the dust loading of the flue gas reached 15 g/m^3." These gas loadings approach the limits expected of a high ash fossil fuel and if localized gas velocities are allowed to exceed 100 ft/sec, erosion can be expected.

The most severe corrosion is reported to occur in furnaces when the radiant superheater has a tube metal temperature of 950°F, or when water wall tube metal temperatures are about 600°F. Nowak (Ref. A-7) summarizes this problem as follows: "The appearance of the corrosion on the tubes in the combustion chamber is similar to that on the finishing superheater tubes. Beneath shell-type deposits, brittle oxidation layers were found. As with the finishing superheater tubes, these tubes were checked frequently with ultrasonic instruments for loss of wall thickness. Here, however, the material loss continues approximately linearly*, while in the superheater the corrosion process is steadily decreasing and approaches an asymptotic limit. The first tube failures occurred after 5500 operating hours. It was noted that the tubes of the wall superheater are affected equally, while the corrosion of the evaporator surfaces is more pronounced in certain areas. These tubes are especially endangered in the corner of the furnace, while there is essentially no corrosion on the furnace rear wall tubes. It should be recalled that the superheater steam temperature is 750 to 825°F while the tube temperature of the evaporator tube is 535°F. No direct influence of wall temperature upon intensity of corrosion is obvious, and it is believed that these results occur as a result of oxygen deficiency in the flue gas composition in various areas of the furnace, the effect of secondary air, and erosion."

Corrosion of possibly two different types might be taking place, one at 950°F plus and the other at a temperature of 600 to 700°F. The literature is not entirely clear in this matter as some investigators report a variety of corrosion phenomena between 600°F and 1100°F (Ref. A-5, -10, and -11). It would appear that temperature, physical location, and local environmental conditions within the furnace all affect the extent and type of corrosion. For example, the corrosion limit for an oxidizing environment appears to be about 850°F. Corrosion can occur at lower temperatures, however, if reducing conditions exist.

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*Loss, in inches, at each 1000 hours (through 5000) equalled 0.0094, 0.020, 0.033, 0.048, and 0.068.

Little mention is made of corrosion at lower temperatures. One area to expect such attack would be at the flue gas exit from the plant because of the low SO_2 levels, high ash loading, emission from air heaters, and relatively high exit gas temperatures from the economizer. Corrosion can be expected during outage periods, although it has not received much attention. Eberhardt (Ref. A-12) indicates deposits of 30-50 percent SO_3 with $CaSO_4$ are hygroscopic and attract water. After a short time an emulsion of H_2O-Fe_2O_3 flows from the heating surfaces and typical dewpoint corrosion occurs.

C. INITIAL REMEDIES

Attempts have been made to minimize these problems with reasonable countermeasures. They have been summarized by Nowak (Ref. A-7).

Corrosion in the furnace was countered by studding the tube surface and covering the area subject to corrosion with refractory. The refractory was placed on those surfaces on which the flame front impinged during operation. The method was used in the Munich incineration plant and 18 months of operating experience was accumulated as of Mr. Nowak's reporting date of November 1968. No corrosion was found under the protective coating. Although a 0.4-in. thick layer of ceramic is not gas tight, it appears that the prevention of slag build-up eliminates the corrosion attack. The lower cooling tubes were protected in the same manner. Most likely these will require a removal of the refractory layer more frequently than the furnace tubes because of the additional erosion.

The convection surface could not be treated the same way, and a different approach had to be taken. The hottest tubes, which were most susceptible to corrosion, were covered with various layers of chromium steel and aluminum oxide by use of different methods. It was impossible to obtain a completely smooth surface, and, as a consequence, corrosion started at pores and continued beneath the protective layers, which then broke off locally.

Shields made of Sicromal were applied to the leading edge of some tubes and both sides of the tube in other cases. The shields were not tightly fitted into the tube. Slag deposits were prevented from coming in contact with the tube material and sufficient corrosion protection was obtained.

Nowak (Ref. A-7) reports that "with these shields, only gas corrosion can be obtained on the tube surface, which does not endanger the tube material. Disadvantageous is the reduced heat transfer rate to the superheater tubes; however, this is not too critical because only the uppermost superheater tubes will be affected."

Another approach being taken is to arrange the superheater in the gas pass of a conventionally fired unit.

For some time it was hoped to eliminate corrosion by the use of additives. All these attempts were unsuccessful. The slag deposits were of a different consistency and were easily removable, but a reduction in corrosion could not be achieved. It also proved too costly to neutralize the relatively large amounts of fly ash by additives.

With regard to a reduction in erosion, Nowak has indicated that areas of highest gas velocities and dust loading should be modified by a suitable design rearrangement based on gas dynamics. He felt the boiler manufacturers would learn from experience how to lay out the system to eliminate this danger. In the field, the operator must use such practical means as shields, baffles, etc.

D. THEORY

The published background just discussed has been the base on which much theory has been discussed in the literature. Most of the theory is centered around chemical reaction based on reducing atmospheres, chlorides, and sulfates. The importance of reducing environments was appropriately based on field experience. The chlorides were considered potentially important based on the presence of polyvinyl chloride (PVC) in the refuse. The sulfates were felt to be important based on U.S. experience and some similarities that appeared to exist.

The theories proposed have been summarized recently in three different papers by Fässler, Leib, and Spähn (Ref. A-4); Defeche (Ref. A-13); and Rasch (Ref. A-14).

1. Corrosion by Reducing Atmospheres

Corrosion due to reducing atmospheres has its origin in the furnace during the combustion stage. It is attributed to improper mixing of air and refuse, allowing some constituents to escape complete combustion. The unspent material travels as part of a laminar flue gas into the cooler zones of the furnace where it contacts various metal surfaces. Part of the problem is attributed to the reverse gas flow in the furnace where some material is destructively distilled off prior to reaching the high temperature combustion zone.

Rasch states the reduction of Fe_2O_3 to Fe_3O_4 takes place easily in an atmosphere containing carbon monoxide:

$$3\ Fe_2O_3 + CO \longrightarrow 2\ Fe_3O_4 + CO_2$$

The reduction of the Fe_3O_4 is more difficult, especially in the low temperature range around 932°F. The reaction is described as follows:

$$Fe_3O_4 + CO \longrightarrow 3\ FeO + CO_2$$

The reduction of iron (II) oxide (FeO) to elemental iron is possible only at high temperatures. At temperatures around 932°F the course of the reaction is proposed to proceed by formation of a carbide phase:

$$3\ FeO + 5\ CO \longrightarrow Fe_3C + 4\ CO_2$$

An investigation of corroded heat exchange surfaces indicates carbonization does occur.

Deféche indicates the reactions are very slow below 760°F, but occur rapidly otherwise. The speed of the reactions, however, is enhanced by the alternating of oxidizing and reducing gas conditions.

2. Corrosion by Chloride Compounds

Chloride corrosion has been attributed to burning of PVC. Fässler et al claim about 50% of the chlorine content of PVC results in the formation of hydrogen chloride at temperatures above 446°F. The hydrogen chloride can also be formed by alkali chloride hydrolysis (due to the high water vapor content of the refuse flue gases) from about 754°F according to the following reaction:

$$2\ NaCl + H_2O \longrightarrow Na_2O + 2\ HCl$$

A third possible source of HCl would result from the reaction between acid sulfates contained in the deposits and alkali chlorides at temperatures from 392°F.

A limited amount of chlorine can also be expected, depending upon the temperature and partial pressure of O_2:

$$2\ HCl + O_2 \underset{1830^oF}{\overset{\text{catalyst}}{\overset{480\text{-}930^oF}{\rightleftharpoons}}} 2\ Cl_2 + 2\ H_2O$$

Fässler reports laboratory experiments indicating that elemental chlorine is released according to the above reaction at temperatures above 662°F when HCl-air mixtures are passed over tube deposits. The formation of chlorine increases rapidly until 1292°F, at which time it stops abruptly. At this point the ash becomes molten. The formation was noted to be inhibited by water vapor.

Wickert (Ref. A-1) reported similar results when passing HCl over iron shavings. The iron chloride that was formed was converted with the oxygen present to Fe_2O_3 and Cl_2 from about 725°F. Water inhibited the formation of chlorine, and increasing amounts of SO_3 practically stopped it altogether.

Laboratory tests by Stellar carried out at 860°F to 1040°F in flue gases from city gas burners with HCl added, showed that the test plates without deposits are hardly attacked. On the other hand, corrosion could be detected on plates with deposits.

Angenend (Ref. A-15) demonstrated in a test facility the increase in corrosion activity of chlorine with temperature. These tests were run in an invironment in which chlorine was added by injecting HCl. Chlorine was also added by incorporating PVC with the refuse burned.

The actual corrosion process has been explained as follows by Fässler:

"Hydrogen chloride or chlorine, in the presence of deposits, can diffuse to the tube surface, where the free HCl or Cl_2 reacts with the surface oxides and metal of the boiler tubes forming iron chlorides (572°F to 752°F). Because the tube wall temperature is low compared to the flue gas temperature, the progress of the hydrolysis is very much retarded. The iron (III) chloride (600°F boiling point) that is formed diffuses to regions of higher temperature within the tube deposit and is decomposed to iron oxides and HCl and Cl_2 in gaseous form (932°F to 1112°F)."

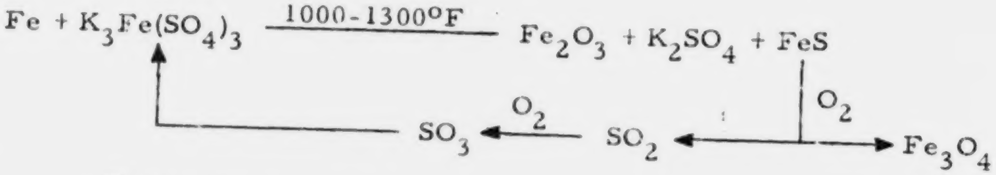
The cyclic reactions described can be represented as illustrated in Figure A-2.

3. Corrosion by Sulfur Compounds

As indicated by Fässler et al, the background on sulfate corrosion is largely based on observations made in coal firing units. In spite of his statement "It has not been possible to this day to find a clear and final explanation of the corrosion mechanism," it is nevertheless possible to summarize the reactions that are being considered by most of the investigators. The greater portion of investigators have tried to relate the corrosion in the refuse units to the pyrosulfate and complex alkali iron sulfate attacks reported while firing coal.

The pyritic attack is usually associated with reducing conditions resulting from flame impingement on water tube walls in the furnace, with temperature ranging between 600°F and 800°F. The corrosion increases with temperature, reaches a peak, and then subsides.

The complex alkali iron sulfate corrosion is usually associated with metal temperatures of 950°F to 1100°F. It frequently occurs on the leading edge of the first few rows of superheater tubes and is strongly dependent on the existence of a liquid phase*. Once again, this corrosion rate increases with an increase in temperature, reaches a peak and decreases once again. The reaction is cyclic and has been described as follows:



Fässler points out that sodium and potassium compounds are completely dissociated in the combustion gas regardless of whether the salts are present in the coal or in the other combustion products as Na_2SO_4, NaCl, etc. The oxides that occur in the ash as a result of a condensation process, such as Na_2O or K_2O, react with the SO_3 contained in the flue gas to form the necessary sulfates. Fässler summarized refuse plant sulfate corrosion interpreted in terms of pyrosulfates and alkali from sulfates in Figures A-3 and A-4.

Sulfate formation is very much dependent upon the SO_2 concentrations in the gas stream. Corey, et al. (Ref. A-16 to -18), indicates at least 250 ppm SO_3 must be present in the gas stream for the formation of the complex alkali-iron sulfate. Normally only 30 ppm SO_3 is present in the flue gas. It is possible the difference is provided by the catalytic conversion of SO_2 to SO_3 in the presence of iron oxide at the tube surface. Recently Battelle Memorial Institute has shown (Ref. A-19) that the SO_3 concentrations at the tube surface may be as high as 30 times the concentration in the bulk stream. Considering the fact that the complex alkali iron sulfate problem is a cyclic process and only small quantities are needed to cause severe damage, the large quantities of SO_3 in a very thin boundary layer at the tube surface may be sufficient to justify the reactions.

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*The melting points of K_2SO_4, $K_3Fe(SO_4)_3$, and $K_2S_2O_7$ are approximately 1900°, 1100°, and 600°F, respectively, as the S content increases from 18 to 25%.

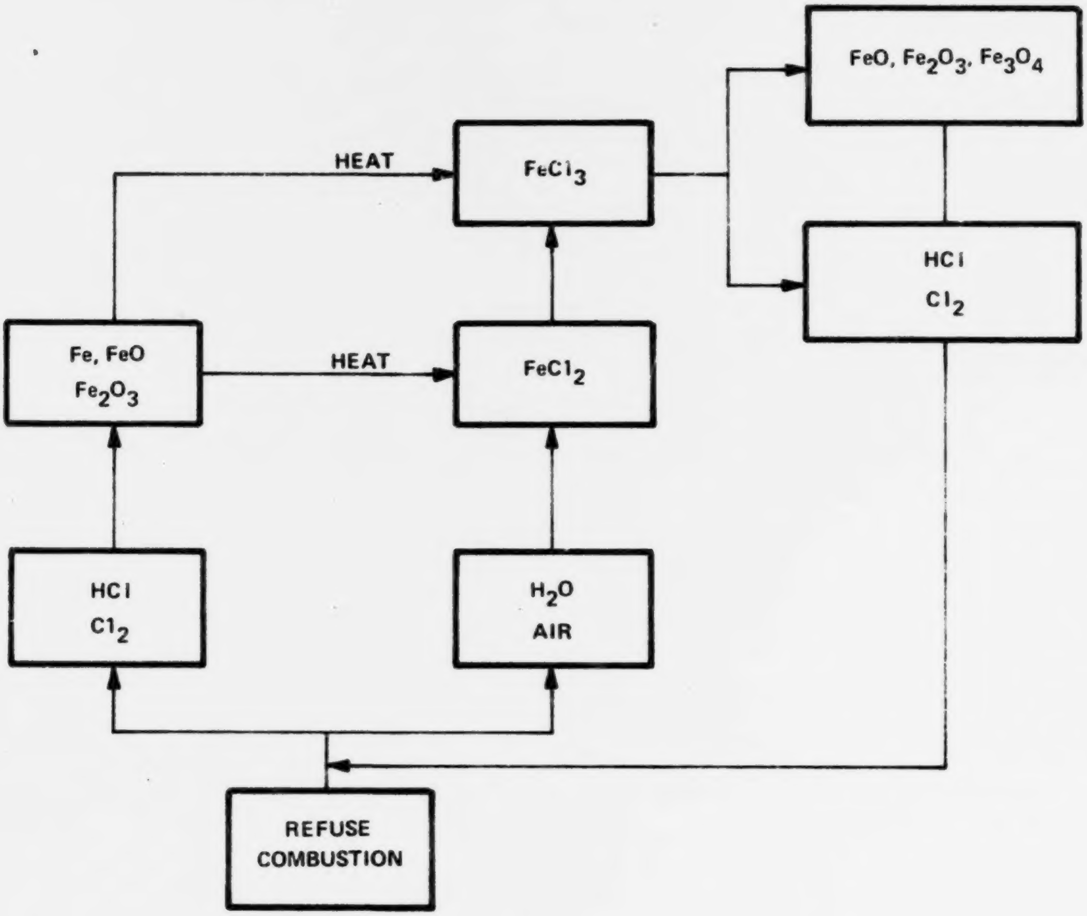
FeO, Fe_2O_3, Fe_3O_4
HEAT
$FeCl_3$
HCl
Cl_2
Fe, FeO
Fe_2O_3
HEAT
$FeCl_2$
HCl
Cl_2
H_2O
AIR
REFUSE
COMBUSTION

FIGURE A-2. CHLORIDE CORROSION FROM FIRING REFUSE

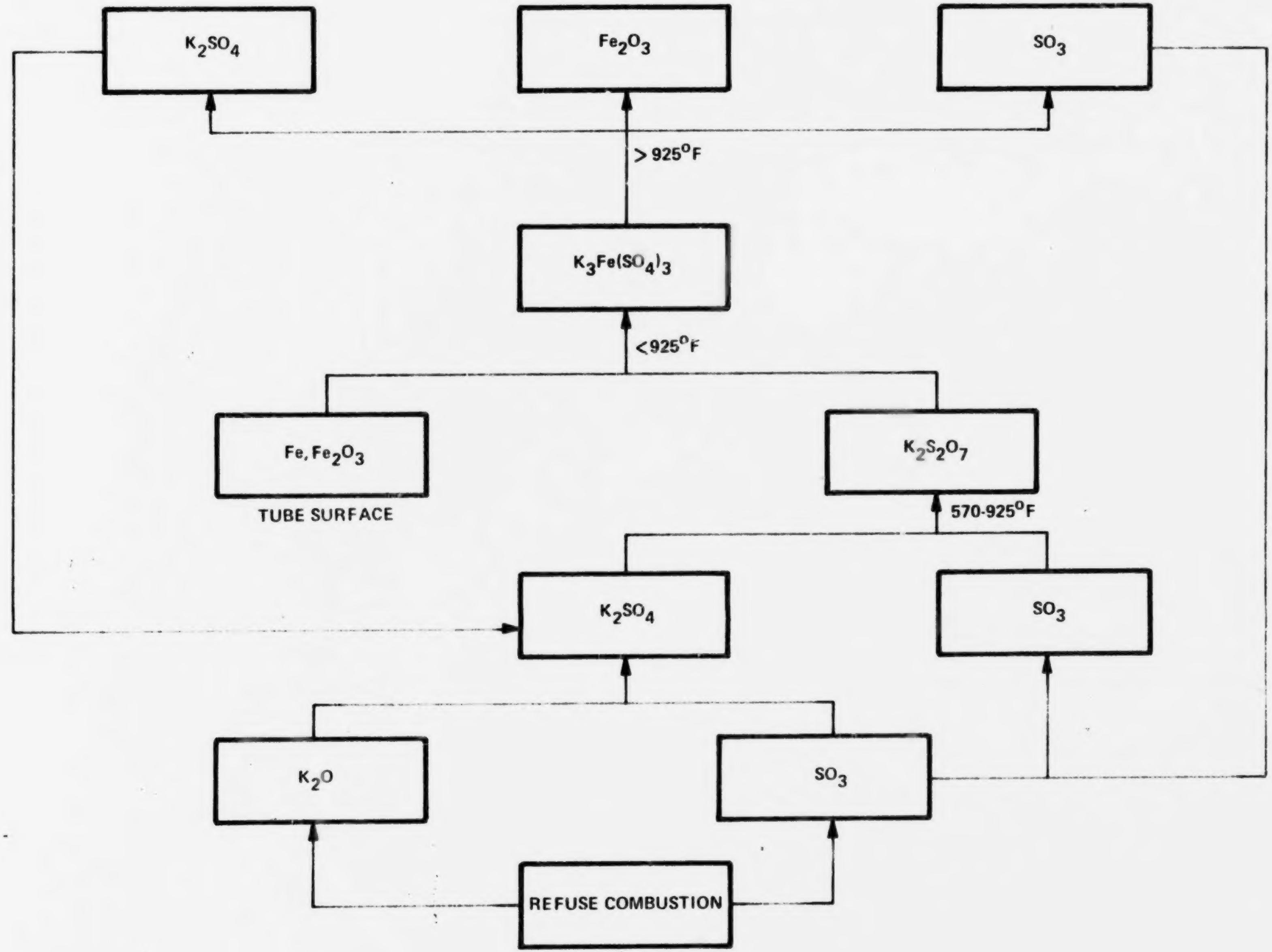
K_2SO_4
Fe_2O_3
SO_3
> 925°F
$K_3Fe(SO_4)_3$
< 925°F
Fe, Fe_2O_3
TUBE SURFACE
$K_2S_2O_7$
570-925°F
K_2SO_4
SO_3
K_2O
SO_3
REFUSE COMBUSTION

FIGURE A-3. ALKALI SULFATE CORROSION FROM FIRING REFUSE

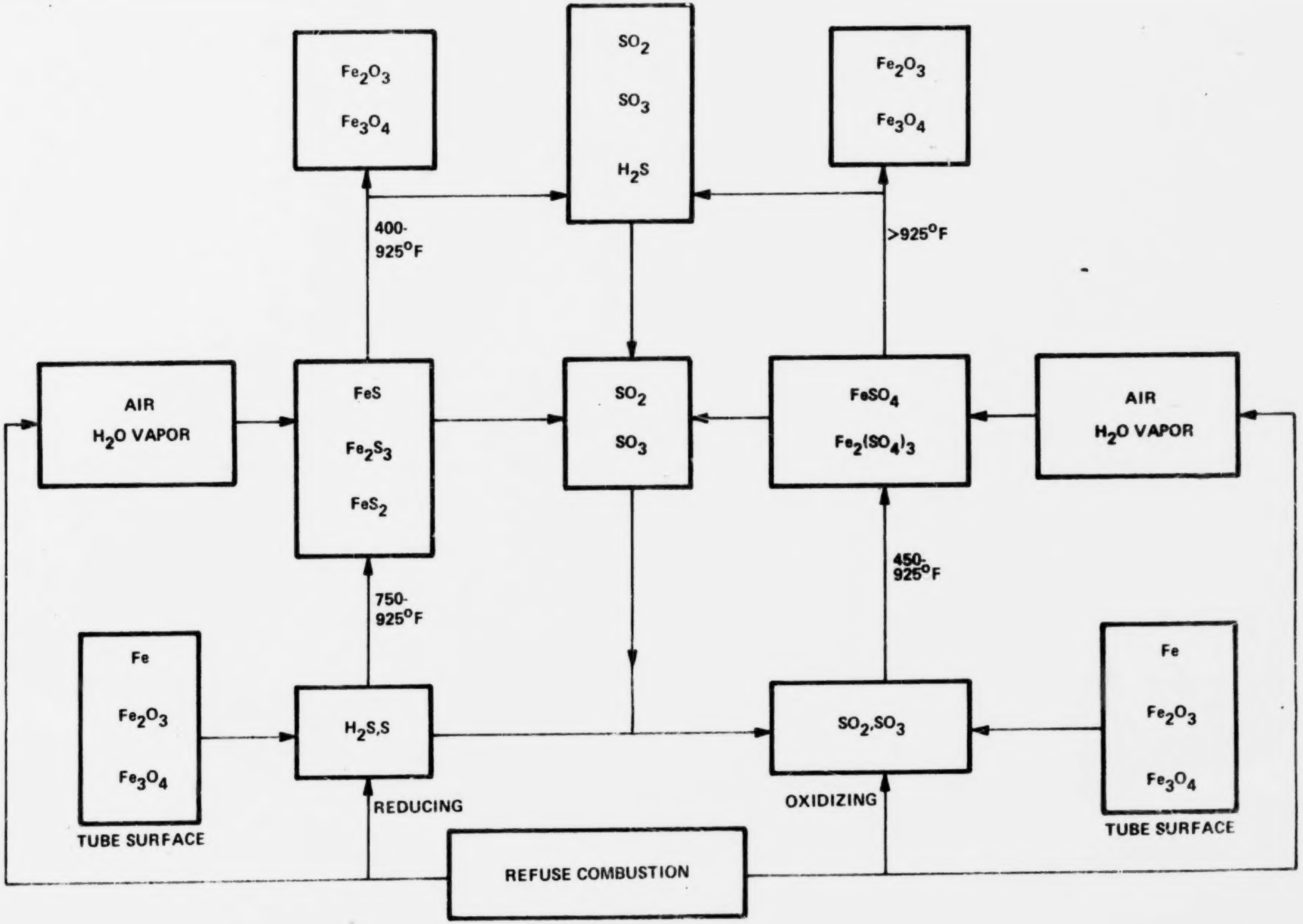
Fe_2O_3
Fe_3O_4
SO_2
SO_3
H_2S
Fe_2O_3
Fe_3O_4
400-925°F
>925°F
AIR
H_2O VAPOR
FeS
Fe_2S_3
FeS_2
SO_2
SO_3
$FeSO_4$
$Fe_2(SO_4)_3$
AIR
H_2O VAPOR
750-925°F
450-925°F
Fe
Fe_2O_3
Fe_3O_4
TUBE SURFACE
H_2S,S
REDUCING
SO_2,SO_3
OXIDIZING
Fe
Fe_2O_3
Fe_3O_4
TUBE SURFACE
REFUSE COMBUSTION

FIGURE A-4. REACTIONS OF IRON AND SULFUR COMPOUNDS

Deféche also suggests that the tubes act as a catalyst, forming SO_3 in the presence of SO_2, with the formation of ferric sulfate as an intermediate compound:

$$2\ Fe_2O_3 + 6\ SO_2 + 3\ O_2 \longrightarrow 2\ Fe_2(SO_4)_3$$

$$Fe_2(SO_4)_3 \longrightarrow Fe_2O_3 + 3\ SO_3$$

A part of this sulfuric anhydride reacts with the alkaline silicates and sodium chloride of the deposits to form alkaline sulfate.

$$SO_3 + Na_2SiO_3 \longrightarrow Na_2SO_4 + SiO_2$$

$$SO_3 + 2\ NaCl + H_2O \longrightarrow Na_2SO_4 + 2\ HCl$$

The silicates are a product of the reaction of alkaline chlorides and of silica:

$$2\ NaCl + SiO_2 + H_2O \longrightarrow Na_2SiO_3 + 2\ HCl$$

The sulfuric anhydride reacts also with the alkaline sulfates to yield pyrosulfates, which attack the ferric oxide protecting the tubes to yield an alkaline sulfate of iron, which is broken up and results in a renewal process. The reactions may be summarized as follows:

$$Na_2SO_4 + SO_3 \longrightarrow Na_2S_2O_7$$

$$3\ Na_2S_2O_7 + Fe_2O_3 \longrightarrow 2\ FeNa_3(SO_4)_3$$

$$2\ FeNa_3(SO_4)_3 \longrightarrow Fe_2O_3 + 3\ Na_2SO_4 + 3\ SO_3$$

In addition to the attack by the alkaline sulfates, Deféche suggests the direct attack of iron by the oxides of sulfur; e. g.:

$$3\ SO_3 + 2\ Fe \longrightarrow Fe_2O_3 + 3\ SO_2$$

He also points out the possibility of sulfite formation through the reduction reactions of carbon and carbon monoxide:

$$2\ Na_2SO_4 + C \longrightarrow 2\ Na_2SO_3 + CO_2$$

$$Na_2SO_4 + CO \longrightarrow Na_2SO_3 + CO_2$$

These sulfites are very unstable and decompose to yield the extremely corrosive sodium sulfide according to the reaction:

$$4\ Na_2SO_3 \longrightarrow 3\ Na_2SO_4 + Na_2S$$

The Na_2S acts in turn on silicon oxide to form a sulfide of silicon that is equally corrosive:

$$4\ SiO_2 + Na_2S + 2\ Na_2SO_4 \longrightarrow 3\ Na_2SiO_3 + 3\ SO_2 + SiO$$

$$SiO + Na_2S \longrightarrow SiS + Na_2O$$

$$SiO + SiO_2 + Na_2S \longrightarrow SiS + Na_2SiO_3$$

$$SiO + CO \longrightarrow SiO_2 + C$$

4. Experiences with PbO

It has been indicated that zinc and lead appear in deposits in relatively large quantities for minor constituents. Lead, in particular, appears to be associated with the excessive oxidation at high temperatures. Sawyer (Ref. A-20) has reported catastrophic damage of stainless steels at elevated temperatures similar in nature to the corrosion by molybdenum trioxide. Buckland, et al, (Ref. A-21) has also reported corrosion due to the presence of lead at elevated temperatures.

There are several possible ways in which corrosion may be taking place. It is possibly due to the thermal decomposition of Pb_3O_4, Newby and Dumont (Ref. A-22) stating that it decomposes at 932°F, which is certainly in the temperature range of the corrosion problem. The equilibrium reaction, describing the dissociation of Pb_3O_4, is as follows:

$$2\ Pb_3O_4 \rightleftharpoons 6\ PbO + 2\ O$$

The dissociation pressure is 5 torr at 832°F, 60 torr at 932°F, 183 torr at 1032°F, and 765 torr at 1170°F. It is conceivable that a cyclic process may occur with frequent changes in flue gas temperature, with the periodic release of oxygen at the tube surface causing the high-temperature corrosion.

The basic lead chloride $PbCl_2 \cdot PbO$ (Matlockite) is another compound included in Newby and Dumont's test that thermally decomposes in the vicinity of 900 to 1000°F. In this case, chlorine, which could be a dangerously corrosive agent, would be released.

A third possibility would involve the reaction of lead chlorides with water at the lower temperature. This reaction could result in the liberation of lead oxide and hydrogen chloride:

$$PbCl_2 + H_2O \rightleftharpoons PbO + 2\ HCl$$

Either compound would be dangerous if the temperature were sufficiently high to cause further thermal dissociation.

As in the case of the alkalies, the postulations regarding lead are not without contradictory evidence. That these lead compounds arrive at the tube without thermally breaking down may be due to the short residence time in the flue gas. Possibly the compounds are formed during the destructive distillation of the refuse and are transported to the tube by the relatively large quantities of excess air present that escapes the combustion process. No explanation can be given for the low-corrosion rate experience with PbO_2 at 950°F.

E. LABORATORY INVESTIGATIONS

There is very little indication of experimental efforts to duplicate field experience in the laboratory and thereby gain a better understanding of the mechanisms taking place. A recent paper by Wickert on "The Accelerators of Corrosion in Furnaces" (Ref. A-1) is virtually the only evidence of such activity. This work, however, is a most significant contribution to the state-of-the-art as it duplicates without contradiction most of the conditions reported thus far in this field. The work deals with the acceleration of corrosion by sulfur dioxide, sulfur trioxide, hydrogen sulfide, hydrogen chloride, oxygen, and water vapor by various constituents found in the ash deposited on boiler tubes; i. e., K_2SO_4, $PbSO_4$, PbO, Na_2SO_4, MgO, CaO, and SiO_2. The tests were run on many 10-CrMo-910 specimens for six hours in oxidizing, reducing, and neutral atmospheres.

Wickert reports that alkali salts accelerate SO_3 corrosion. His experiments demonstrate that the test gas (air with 2 vol-% H_2), 0.7% SO_3, and 0.3% SO_2) caused a weight gain of less than 0.0008 lb/ft^2 up through 1650°F, whereas in the presence of Na_2SO_4 a maximum gain of 0.026 lb/ft^2 was observed at 1200°F (0.0070 lb/ft^2 at 1100° and 1430°F). At the higher temperatures, SO_3 dissociates to form SO_2 and the activity of the SO_3 molecule falls off. It was also established earlier in his paper that the Na_2SO_4 does not accelerate the O_2 corrosion, but only the SO_3 corrosion. He points out that no substance other than V_2O_5 has been found to accelerate O_2 corrosion.

Wickert shows that the alkali salts also accelerate HCl corrosion. In these experiments, the test gas alone (air with 10 vol-% H_2O and 0.5% HCl) caused weight losses of 0.0035 and 0.018 lb/ft^2 at 930 and 1100°F, respectively, and with K_2SO_4 present, losses of 0.0087 and 0.055 lb/ft^2 were observed at these temperatures. Wickert's tests show corrosion in this case may take place in the absence of a liquid phase. He reports that the K_2SO_4 placed on the steel sample was completely loose after the test. In that no SO_2/O_2 or SO_3 were present in the gas, no bisulfate melts could be formed.

Further tests with NaCl and Na_2SO_4 in an oxidizing environment indicate the potassium sulfates were most corrosive, followed by the alkali chlorides, and then sodium sulfates. Mixtures of equal parts of sodium and potassium sulfates are more corrosive than either constituent by itself. K_2SO_4 in the absence of HCl more strongly accelerates SO_2/O_2 corrosion than Na_2SO_4, and the same is true for HCl corrosion accelerated by the two alkali sulfates in the absence of SO_2 or SO_3. The corrosion that is not accelerated is light. The alkali salts accelerate the SO_3 or SO_2/O_2 corrosions, but not the SO_2 corrosion. In the absence of O_2, SO_2 also corrodes the steel, but this reaction cannot be accelerated.

CaO and MgO occur in ash deposits along with the alkali salts. Wickert indicates that in a gas containing 0.5 vol-% HCl, 0.6 vol-% SO_2, and 10 vol-% water, CaO accelerates corrosion above 1032°F (seven times faster at 1100°F). Below this temperature it retards the reaction slightly. MgO behaves in the same manner but the acceleration is not nearly as great (0.012 lb/ft^2 for the test gas at 1100°F vs 0.018 lb/ft^2 in the presence of MgO). The alkali salt accelerators increase their action in air with H_2O, SO_2, and HCl starting at 750°F if they are mixed with CaO. MgO-alkali salt mixtures retard the action of the pure alkali salts, but they do increase the straight gas corrosion.

If CaO and MgO are combined with Fe_2O_3 as ferrites, the gas corrosion is increased only above 1032°F. Mixtures of CaO-Fe_2O_3 or MgO·Fe_2O_3 with K_2SO_4 in a weight ratio of 1:1 reduce the gas corrosion that is accelerated by K_2SO_4 alone. At 1100°F they accelerate the straight gas corrosion.

In gases in which HCl is not present, it was found that CaO and MgO are not accelerants of SO_2/O_2 or SO_3 reactions up to 1000°F. They do not retard the gas corrosion and the corrosion normally accelerated by K_2SO_4. They also reduce the activity of the accelerator. The ferrites of calcium and magnesium behave similarly to CaO and MgO.

In an HCl environment containing no SO_x, CaO is a strong reaction accelerator. MgO increases the reactions only slightly.

Wickert investigated other substances also. He found that Fe_2O_3 does not accelerate the reaction of air, 10% water, 0.6% SO_2, and 0.5% HCl. Ferrous sulfate, ferric sulfate, and zinc sulfate do not accelerate the gas corrosion either. They only cause a slight increase in the gas corrosion at higher temperatures because of splitting off of SO_2, SO_3, and O_2. The chemically pure sulfates of the alkaline earth metals are very weak corrosion accelerators; $CaSO_4$ and $BaSO_4$ accelerate the reactions above 1100°F, while $MgSO_4$ has no noticeable influence. The $CaSO_4$ product formed in the gas stream from CaO accelerates very strongly above 1100°F and the sulfate from MgO noticeably. Wickert assumes that the residual oxide content is responsible for the difference.

According to Wickert, $PbSO_4$ accelerates the corrosion reactions considerably above 950°F for gases containing HCl as well as SO_2 or SO_3. He also found that $PbSO_4$ is inactive in a dry gas and accelerates corrosion in the presence of water vapor.

It was found that PbO increased the corrosion rate in the presence of $PbSO_4$ in a manner similar to that of CaO and $CaSO_4$. When PbO was used as a reaction accelerator, weight loss was six times more rapid at 1100°F than with $PbSO_4$ and deep corrosion pitting occurres in the short period of six hours.

With a wet gas containing HCl and SO_2, it was found that mixtures of $PbSO_4$ + CaO (2:1) and $PbSO_4$ + MgO (2:1) greatly increased the gas corrosion. A loss of 0.049 lb/ft^2 was noted at 1080°F for both mixtures, compared to 0.012 for the gas alone and 0.021 lb/ft^2 for the gas plus $PbSO_4$. A $PbSO_4 \cdot SiO_2$ mixture retarded the corrosion to the level of the straight gas.

It is possible that the balance of SO_2 and SO_3 in flue gas is such that chlorine could form from HCl present. Tests run with Cl_2 in the gas indicated that K_2SO_4 is a strong accelerator for its corrosion mechanism.

Tests were also run in neutral and reducing environments. It was found that SO_2 corrosion was not accelerated by alkali metal salts in the absence of O_2. Acceleration of HCl corrosion did not require O_2. In tests run with K_2SO_4 and HCl, the solid coating on the metal sample after the tests at all temperatures contained relatively large amounts of combined chlorine. The water extraction had an acid reaction. If the reaction gases contained SO_2/O_2 in addition to HCl, after the test there was only a small amount of combined chlorine in the coating. On the other hand, if CaO was present instead of K_2SO_4, then the coating after the test again contains more combined chlorine.

K_2SO_4 was found to be a strong accelerator (14x at 1100°F) for HCl corrosion in wet neutral gas. At 750°F the coating was fused, and at 950°F it was sintered; it contained chlorine at all temperatures.

In a reducing environment, the corrosion due to K_2SO_4 with and without SO_2 and HCl and mixtures of these two gases was heavy and began at lower temperatures, as low as 600°F for some tests. The corrosion product in tests involving a reducing atmosphere contained FeS.

and the combustion gas contained organic sulfur compounds, sulfur, and hydrogen sulfide. When K_2SO_4 was used as an accelerant, the corrosion products contained organic sulfur compounds, sulfur, and hydrogen sulfide.

In summary, Wickert indicates that, with few exceptions, the ingredients found in refuse deposits accelerate gas side corrosion above 950°F. In the presence of a reducing condition the threshold temperature could be reduced to as low as 600°F. The deposits were fused and revealed the presence of H_2S. In an oxidizing atmosphere containing HCl, it was found that corrosion could take place in a "dry" unfused, powdery ash.

II. EXPERIMENTAL

A. DISCUSSION

On the present program, analyses were run at the Foster Wheeler Corp. laboratories on composite samples removed from approximately 30 different locations in each of the boilers under study in Europe. Fewer sampling locations were used in the boilers examined in the United States. The sampling points include numerous locations on all four walls of the furnace representing several elevations, upstream and downstream sides of tubes located in the superheater bundle, and numerous locations in the economizer. These sampling points provided a good representative sampling of the ash deposited during flight through the boiler at various temperature levels and gas-tube temperature gradients. In some cases the corrosion produced was removed intact with the ash samples. In other cases the corrosion product remained tenaciously attached to the tube. Fortunately, on several occasions, the layer adjacent to the tube surface could be removed from the tube as a sample separate from the bulk deposit. The latter group of samples was analyzed as a separate group.

In the beginning, the first few samples were analyzed for a large number of elements on the assumption that most elements could be found in refuse to some degree. The analytical procedure was soon reduced to include only those elements appearing most frequently and the elements which were of the most concern.

Tabulation of the results summarized in Table A-3 reveals numerous interesting facts. As suspected at the start, the ash deposited very much resembled lignite ash and contained relatively large quantities of calcium in proportion to the iron present. This similarity was confirmed by relatively low ash softening temperatures. If the chemical composition in terms of the basic* constituents present are compared with

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*Calculation of the level of basic or alkaline constituents follows the convention of omitting from the other constituents the Zn, Pb, and S present.

TABLE A-3

TYPICAL ASH ANALYSES (WT-%) FROM DIFFERENT BOILERS

Constituent	Europe			United States	
	Boiler 1	Boiler 2	Boiler 3	Refuse	Lignite
Al_2O_3	16	17	8	11	11
SiO_2	11	13	15	26	18
Fe_2O_3	2	5	4	4	12
CaO	16	8	10	9	24
MgO	2	2	2	2	8
Na_2O	3	2	4	6	7
K_2O	9	9	9	10	1
PbO	3	6	5	2	-
ZnO	4	8	6	8	-
SO_3	33	30	31	20	15

the ash softening temperatures in Figure A-5, it can be seen that this same relationship holds for refuse and lignite. The lignite data shown in Figure A-5 are Duzy's (Ref. A-23); the refuse ash data were generated by Foster Wheeler Corp.

This analogy is also somewhat substantiated by the relatively large quantities of sodium and potassium appearing in the deposit. Sodium varies between 0 and 5%, while potassium runs a little higher; both constituents appear in the deposits consistently throughout the boiler. Their presence becomes more pronounced in deposits from boiler zones having lower gas temperatures.

The findings on chlorine were rather surprising. For the most part, it was conspicuously missing from the European deposits. It did appear in small percentages (about 1% or less) in the ash removed from both of the domestic boilers sampled. In the two cases in which it exceeded these percentages, the sodium present was also proportionately high. No corrosion was associated with either of these two cases. It is possible that chlorides did appear in larger concentrations in a very thin layer lining the inside surface of the ash sample.

Zinc and lead were found in relatively large quantities. Neither of these two elements was anticipated. Zinc, like sodium and potassium, appeared rather consistently in most ash sampled. It ran between 9 and 10% and increased in concentration with a decrease in gas temperature. Lead appeared somewhat sporadically, ranging from 0 to 13%. Presumably these two elements are found in refuse as pigments, solders, galvanized coatings, etc.

The minor constituents, which are usually defined as sodium, potassium, zinc, and lead, comprise about 18-25% of the ash sampled at gas temperatures below 1700°F. The concentrations decrease with an increase in temperature above this point, being approximately 15% at 1800° and 10% at 2000°F. It was further noted that a rather constant relationship appears to exist between the percent zinc and the combined percentage of sodium and potassium. This relationship is best fit by the equation $\% \text{Zn} = 1.12 (\% \text{Na} + \text{K}) - 1.71$. If lead is included with the zinc, it is found that a linear relationship still exists, but in slightly different proportions. This could be interpreted to mean that zinc, sodium, potassium, and lead are depositing as some discrete compound or that liquid solutions are solidifying at a particular composition. An examination of the ternary system of Na_2SO_4, K_2SO_4, and $ZnSO_4$ indicated the percent zinc, sodium, and potassium were reported in proportions that coincided with low melting temperature phases (720-740°F) in this system (30-50% K_2SO_4, 40-60% $ZnSO_4$, and 10-30% Na_2SO_4).

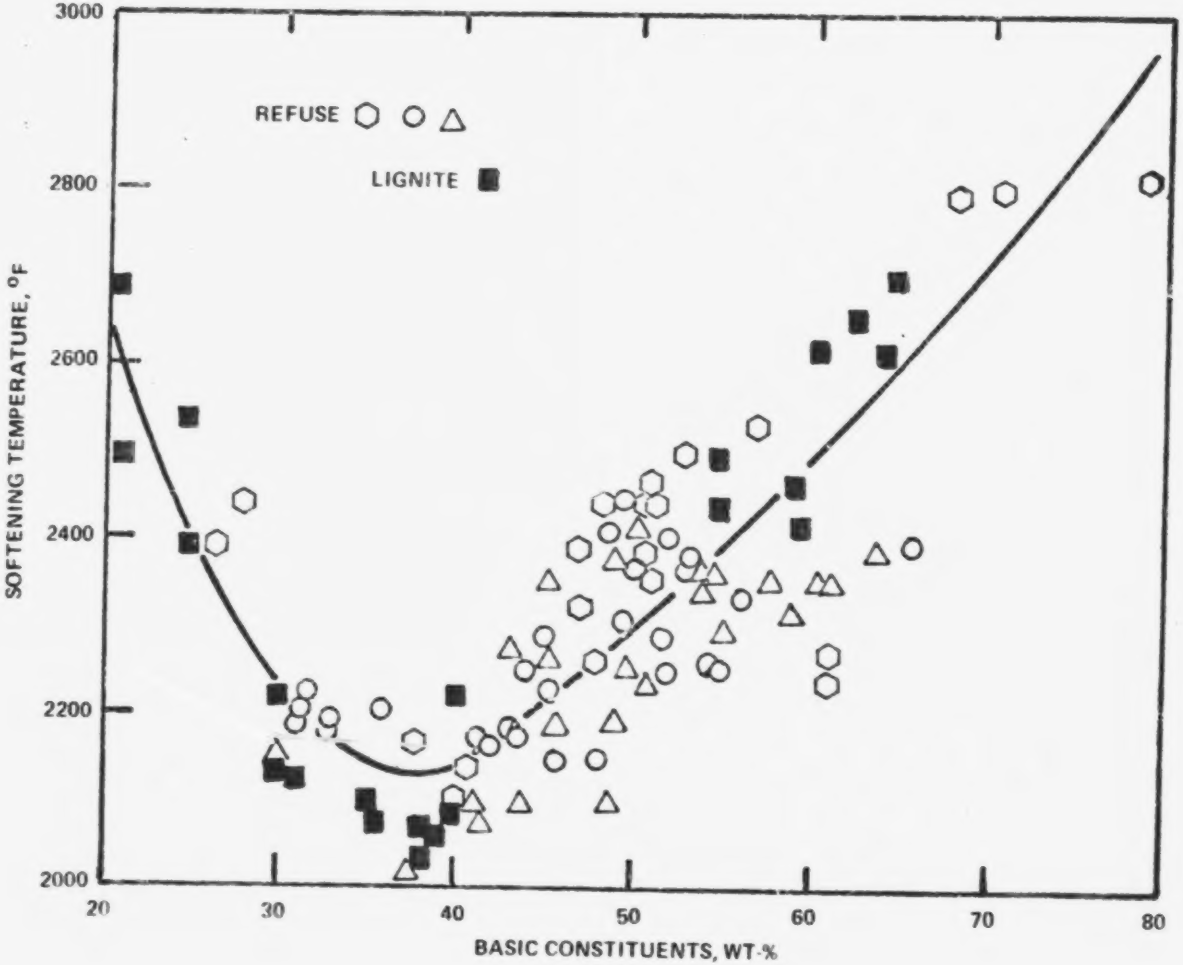

FIGURE A-5. SOFTENING TEMPERATURE VERSUS ASH BASE CONTENT

Chemical analyses were run on ash samples that comprised only the inner layer of ash, either lining the corrosion product or the tube surface. These analyses (Table A-4) indicate the presence of large quantities of lead and potassium. In most cases, the percent lead in the inner layer was 2 to 5 times greater than reported in the bulk sample. Considerably less difference was observed in the potassium distribution. Zinc and sodium were present in substantially lower quantities, and their level of concentration apparently was not dependent upon location in the ash deposit. Ash fusion tests with conventional tetrahedron cones indicated that portions of the ash can be expected to be liquid at temperatures as low as 1200-1700°F. The inside layer of one sample (removed from a domestic boiler) that contained large quantities of lead, had an initial deformation temperature as low as 850°F. Unfortunately, no relationship could be established between the presence of a liquid state and chemical composition, a much more sophisticated procedure apparently being required. It is possible that small portions of a liquid phase could form at low temperatures and remain undetected due to the wetting of the larger quantity of dry material.

In general, the chemical analyses indicate that the ash compositions in all the boilers analyzed were very much alike. It would be reasonable to assume that the results could be compared or extrapolated from one boiler to another if the operating conditions were similar and the refuse was within the compositional range normally found.

Practically all samples were examined microscopically as well as chemically in order to detect clues that might shed light on the nature of deposit corrosion. There was strong evidence that most of the chemical reactions responsible for the deposit problem took place at the tube surface. Sintered ash found in the convection passes, as well as the furnace, consisted of small spherical particles of fly ash 10 microns in diameter or less. Particles forming perfect spheroids indicate that they must have been molten and solidified at one point in their flight through the boiler, during which time the aerodynamic and gravitational forces were in balance. At this point the particles behaved as a part of the gas stream. They must have reached the tube surface by diffusion in a dry state after they had solidified. This is confirmed by the fact that much larger particles, which are subject to greater inertia forces, manage to pass through the maze of tubes in the convection passes before collecting in the cooler zones.

Close examination of the deposits on a layer by layer basis revealed that the particles comprising the inner layer show much greater evidence of reaction with other constituents. The spheroids were distorted and had a frosted appearance. Particles of fly ash situated on the outer surface were predominantly perfect spheroids of clear "unreacted" material. Much larger spheres of this description were also found at the cold end of the convection pass.

TABLE A-4

COMPARATIVE ANALYSES (WT-%) OF BULK AND INSIDE LAYERS OF ASH SAMPLES

Constituent	Sample 1		Sample 2		Sample 3	
	Bulk	Inside	Bulk	Inside	Bulk	Inside
Al_2O_3	10	5	19	4	11	4
SiO_2	21	12	30	9	20	6
Fe_2O_3	12	5	7	3	4	18
CaO	10	6	11	7	9	2
MgO	3	1	3	-	2	-
Na_2O	-	2	3	3	6	5
K_2O	6	8	7	11	10	13
PbO	3	16	1	17	2	6
ZnO	6	6	6	6	8	9
SO_3	14	36	24	40	20	26

Fused ash was found in the high temperature gas zones, but not necessarily in those having the highest gas temperatures. Frequently, the fused ash was preceded by accumulations of light sintered ash, indicating unusual conditions existed when the deposits were forming. Gas temperatures in these zones were estimated to be as much as 390°F below the initial ash deformation temperature measured in the laboratory. In numerous cases the inner layers of the deposits found in the cooler zones were fused, while the other layers were sintered or almost powdery. Deposits forming on the upstream side of the tube were fused solid, while ash of the same composition accumulated on the downstream side of the tube was powdery. Past experience with ash deposits and recent work by Bishop (Ref. A-24), indicate that vaporized compounds of minor ash constituents, such as sodium, vanadium, etc., can condense as solids on surfaces whose temperatures are well below the triple point even under conditions of high gas velocity.

Examination of the deposits revealed several other facts concerning the ash deposit/corrosion problem. In many cases fused deposits, when broken open, released a strong smell of sulfides. It is apparent that despite the large quantities of excess air used in the boilers from which the samples were taken localized reducing conditions existed. In one of the boilers examined in the United States, the corrosion and ash deposition on the tubes was heaviest in the portion of the tube bank either subjected to flame impingement or in the immediate vicinity of the combustion zone.

Corrosion observed while removing the ash samples varied throughout the boiler. With few exceptions, corrosion was associated with the formation of the ash deposited. In some cases, the corrosion product was removed with the deposit as a loosely attached scale. In other cases, the corrosion product adhered tenaciously to the tube and had to be separated from the ash. In one or two cases in the high gas temperature zone of the boiler, there was evidence of a crystallized material lining the tube side of the corrosion product. Although this phenomenon was confined to a given section of the boiler, it was noted in several different units. No attempt was made to identify the crystallized material.

Corrosion reported in the furnaces of most European boilers largely involved a zone on the furnace walls which would be outlined by the projection of the flame shape onto the tube surface. This same area was reported to be subjected to localized reducing conditions. The corrosion product could usually be removed from the tubes as an intact scale having a thin layer of sintered ash.

B. CORROSION TESTS

Corrosion tests were run on all samples removed from metallic surfaces by simply soaking small metallic specimens weighing about 15 to 20 grams in approximately 4 grams of ash for about 140 hours at 750°F and

950°F in an oxidizing atmosphere. Each specimen measured approximately 1 in. x 1/2 in. x 1/4 in. and offered about 0.45 in.^{2} of surface area. When soaked in the ash, about 1/4 of the specimen was submerged in the ash and 3/4 was exposed to a normal atmosphere. All the specimens had a ground surface finish.

All samples were cleaned with a solvent before the tests. After the tests, they were descaled in a hot sodium hydroxide dip and 8% HCl solution inhibited with rudine. This was followed by a water rinse and acetone dip.

The purpose of these tests was not to determine the oxidation rates but to qualitatively indicate the type of attack and its order of magnitude. Such a procedure was successfully used in studying the effects of additives on the catastrophic oxidation of boiler tubes caused by vanadium pentoxide. This type of test often reveals slight changes in the physical characteristics of ash not normally indicated by standard technique.

The results of the tests are difficult to analyze, as there were no obvious trends noted in the large quantity of data obtained. However, there is some agreement between field observation and the laboratory results. Most of the corrosion took place at the 950°F level, although less severe corrosion was experienced at 750°F on several occasions. Two types of corrosion were noted. In one case, a brittle scale was formed around the coupon that could easily be removed with the fingers. No liquid phase was present in the ash, and the attack above and below the ash line was the same. The evidence suggests corrosion promoted by the gaseous phase. In the second case, a tight adhering scale was formed in the presence of a liquid phase in the ash. The surface of the coupon below the ash line was obviously pitted. Unfortunately, no relationship could be established on the basis of chemical composition. Those few samples containing large portions of chlorides did not necessarily show signs of excessive corrosion. In many cases, the corroded speciments were those that were soaked in ash that had been removed from boiler zones where corrosion had taken place, while little corrosion was noted on coupons immersed in deposits obtained from boiler zones where only slight corrosion occurred. However, this situation did not hold for all cases, undoubtedly because of the lack of duplication of boiler environment.

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APPENDIX B

STATE OF THE ART SURVEY

I. INTRODUCTION

The purpose of this appendix is to provide an information compilation that will describe the state-of-the-art, economic aspects, and emerging design characteristics of steam generators. Emphasis has been placed on systems that operate with steam conditions that are compatible with turbo-electric applications.

A brief review of the recent history in the development of the design-technology is presented, and predictions offered as to the future direction steam generator design will take.

Cost and performance data, covering ten different boiler configurations, considered to represent the essentials of domestic practice, have been summarized. Cost data for European systems have also been organized and are presented for comparative study. Because German practice furnishes an excellent cross-section of modern European steam generator technology, data generated in that country have been used.

To demonstrate the relevance of utility-scale boilers and those suitable for refuse-firing, a review of what may be considered the intermediate classes of boilers has been documented. These are comprised of units which fire inferior fossil-fuels and waste fuels.

The nature of emissions produced in power boilers constitutes a logical topic for this appendix, as does the methodology practiced for their control. This discussion includes consideration of both extant and advanced systems, and the impact that foreseeable air quality standards will have on this field of engineering.

The final topic presented deals with the state-of-the-art of utility-class steam generators which are fired by refuse, either as the sole fuel or in combination with conventional fossil-fuels. At the present time, there are no true examples of such systems in the U.S. This review has therefore been confined necessarily to European experience; more specifically, to German units. Information is presented on the design characteristics of five German plants, together with performance-test data generated by the Technische Überwachungs Verein (TÜV).

II. SUMMARY AND CONCLUSIONS

In maintaining pace with the exponential increase in energy demand, the evolution of power-boiler design has been fast-paced and dramatic over the past several decades. New engineering, fabrication, and operational developments have profoundly influenced design-practice, as has fuel cost and the consequent need to accommodate lower-grade fuels. Unit sizing has reflected industry's reaction to power-demand pressures; 1200 and 1300 MW units are now being built and 3000 MW units can be expected by the year 1987. In the drive to achieve increased unit capacity, steam conditions also underwent a steady increase. The constraints posed by operation in the supercritical region have now resulted in a trend or return to subcritical units of the natural circulation type.

This trend, however, has not been followed in Europe, where the once-through boiler predominates. In spite of this and other differences, it can still be said that European boilers reflect rather closely the best design practices used in this country.

In considering present and future generation power boilers as possible convertible systems for the combined-firing of conventional fuels and refuse, certain problems must be faced. Because of the steady increase in unit size and the thermal fluctuations caused by variations in the calorific value of refuse, the amount of the latter to be fired, in proportion to the regular fossil fuel, will probably be limited. In the case of coal, at least, the practices now often used in transporting the fossil fuel may have an important effect on refuse haulage costs. A present trend in new unit construction is to locate power-boilers close to coal-mining areas. Because of new transmission-line fabrication techniques, it is cheaper to conduct electricity to the use-point than to bring coal there from the mine-mouth. Thus, the future use of retrofitted power plants for refuse-firing may well require the use of older units, which are reasonably centralized, or the consideration of advanced concepts of long-distance refuse conveyance.

In terms of the design of units to be used specifically for combined- or refuse-only-firing, European experience has shown that the engineering concept is practical. Units are now in operation which provide steam conditions that are consistent with conventional power-boiler characteristics. This has not resulted in the serious corrosion problems expected by many, although a greater corrosion nuisance does apparently exist than when firing with fossil fuels alone.

The direction of current U.S. designing, which will shortly result in the first combination-fuel turbo-electric boiler, is to suspension-firing of the shredded refuse. Although the principle has been successfully demonstrated with other waste fuels, its application to refuse-firing should be carefully monitored. This step represents a leap beyond the technology now practiced in Europe, where raw refuse is fired on agitating grates, or, at most, only bulky items are previously reduced in size. Indications are that the firing of ground refuse in suspension, or even on an agitating grate, will result in faster burning rates, better burn-out, and a reduction of ash-bulk.

The air pollution control devices now in popular use in Europe are almost exclusively aligned to particulate removal. The system favored for this function is the electrostatic precipitator. Because of the low sulfur-content of the coal used in Europe, there is less concern regarding sulfur oxides emission control. In this country, low sulfur fuels are not as available; thus, a different emission control problem exists. It is obvious that the advanced processes, now in development and in early industrial application, for the control of emissions of sulfur oxides from conventional power plants, will also have to be considered for combined-fired boilers.

III. STEAM GENERATORS

A. HISTORY AND TECHNOLOGY

1. Historical Development

The progress in the development of fossil fuel fired power systems since the days of Thomas A. Edison and his contemporaries has been spectacular. Steam conditions have increased from about 100 psig and saturated temperature to superheat and supercritical pressures. Unit sizes have grown from around 100 kw to the 1,500,000 kw range. The Edison Plant, Pearl Street, New York, in 1882 had a heat rate* of 138,000 Btu/kw-hr. Today's plants have heat rates approaching 8,500 Btu/kw-hr.

In the first half of this century, advances were in the form of a gradual evolution, setting the groundwork for the explosion of technology that occurred during the second half of the century. By 1937, the general trends in steam generator design, which had long been accepted practice, were listed (Ref. B-1) as follows:

- Adoption of superheaters and economizers.
- Substitution of water- and steam-cooled furnace walls for refractory surfaces.
- Removal of coal firing equipment from the inside to the outside of the furnace**.
- Progressive increase in the size of individual units.
- Progressive increase in steam pressures and temperatures as boiler materials and manufacturing techniques improved.
- Use of steam separators to prevent carry-over of water to the superheater and turbine.

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* Speciality terms are defined in Appendix E.

**The use of pulverized fuel firing systems became almost general since their initial trials in 1919 (Ref. B-2).

The above trends, although described many years ago, applied only to non-reheat, natural circulation boilers producing less than 1,000,000 lb/hr of steam under conditions of about 1500 psig and 900°F. In 1937 the first steam generator with a design pressure above 2000 psig was developed and by 1939 the steam pressure had reached 2335 psig (Ref. B-3). The technology explosion began in the post-WW II years and advanced rapidly. By 1952, the trends observed (Ref. B-4) were as follows:

- Designs accommodate lower grade fuels without economic penalties.
- Cycle efficiencies improved to offset increasing fuel, labor, materials, and construction costs.
- Feedwater treatment improved.
- Evolution of combined and forced circulation.
- Pressurized combustion.
- Combustion of crushed coal.
- Development of "quick-starting" techniques.
- Introduction of welded panel-walls.
- Excursion into the high pressure domain.

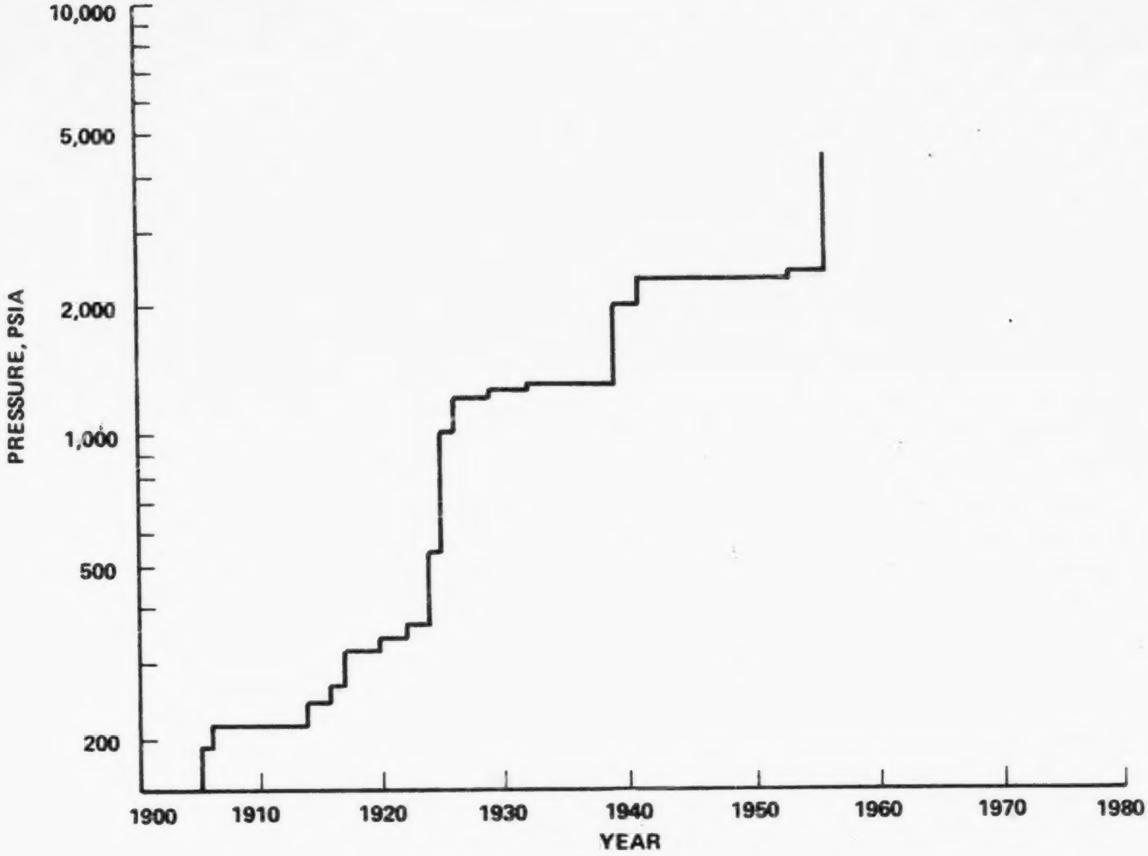
These trends, which are discussed below, still operate at the present time.

a. Fuels

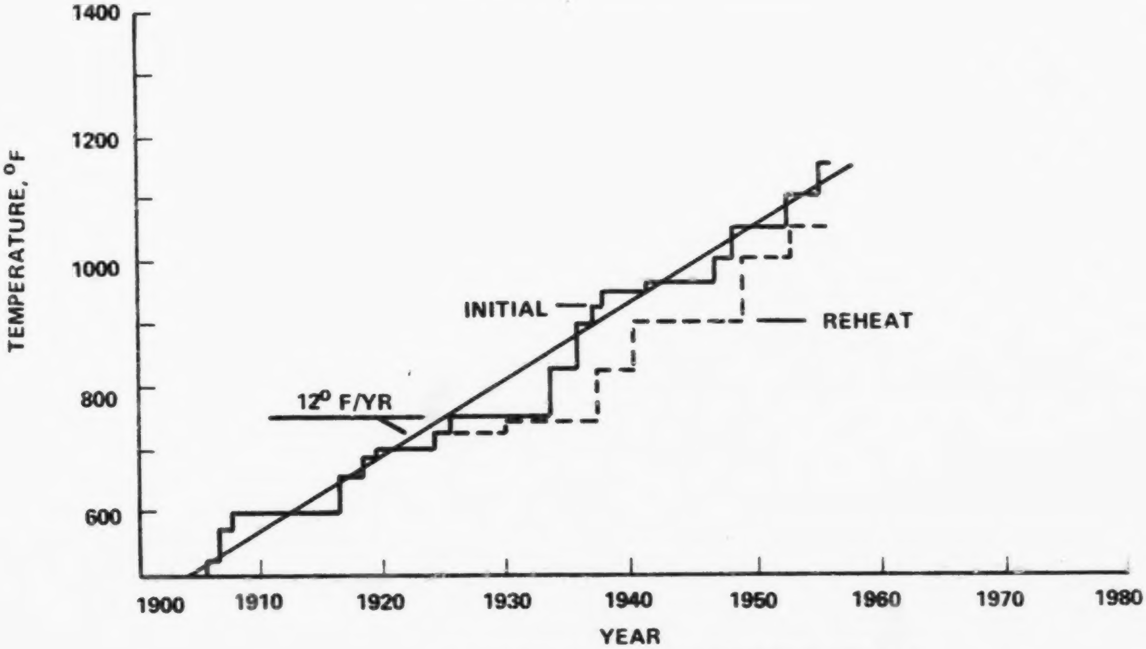
The expanding power demands have necessitated that less desirable fuels be burned. This has included lower grades of coal and also the use of imported oil crudes containing vanadium and sodium.

b. Cycle Efficiency Improvements

During the immediate post-war period, steam conditions of 2400 psig/1000°F were being used. A graphical recounting of steam pressure and temperature increases up to and including 1955 are illustrated in Figure B-1. Various techniques of superheating were being employed and reheating of steam had become the norm of the industry (Ref. B-5). Regenerative heating, an attempt to minimize the effect of the irreversibilities of the Rankine cycle, was also widely practiced.



A. MAXIMUM STEAM PRESSURES



B. MAXIMUM STEAM TEMPERATURES

FIGURE B-1. HISTORICAL TRENDS IN STEAM CONDITIONS

In 1952, unit sizes of 200,000 kw were in operation; by 1953 units of 250,000 kw were on order (Ref. B-6), and units of 300,000 kw were predicted (Ref. B-7). Because the limits of steam generator efficiencies had long been achieved, the search for improvements in cycle efficiency was concentrated on prime movers (turbines) and accessory equipment. Further increase in the unit size of the steam generator (and, thus, cycle efficiency) awaited the development of the 3600 rpm turbine (Ref. B-8).

A comprehensive treatise on steam turbine developments was given in 1954 by Franck (Ref. B-9).

c. Feedwater Treatment

As steam pressures and temperatures were increased, new specifications for water quality had to be developed. This was especially necessary for units operating near or above the critical pressure. Experience showed that water of exceptionally high purity was necessary in order for large steam generator-turbine units to perform with high availability.

d. Circuitry Evolution

As later discussed in further detail, the natural circulation steam generator was joined, although not supplanted, by other types of boiler circuitries. These included the forced circulation and the various types of "once-through" designs. While these newer systems offered a modest gain in efficiency, drawbacks existed which tended to make the natural-flow circuit a still very attractive configuration.

e. Pressurized Combustion

Three basic methods of firing developed: natural-draft, balanced-draft, and pressurized. In natural-draft furnaces, no fans are used; in balanced-draft systems, both a forced-draft and induced-draft blower are used; in a pressurized system only a forced draft fan (handling cool air only) is used. A savings in total fan horsepower of approximately 20 percent is thus realized in pressurized furnaces. However, the latter require particular design attention with respect to furnace tightness, since outward leakage of furnace gases cannot be tolerated. Gas tight protection must be provided at literally hundreds of places, including observation ports, air heater seals, damper seals, doors, burners, soot blowers, and certain parts of the pulverizers. The advantages implicit in pressurized firing are better realized with ash-free fuels such as natural gas and oil.

f. Combustion of Crushed Coal

The first commercial cyclone-burner firing crushed coal was installed in 1944. By 1954, twenty-five such boiler units had been placed in service (Ref. B-10). The main advantages of the cyclone furnace were the elimination of coal pulverizers and reduction in the carry-over of fly ash.

g. Quick-Starting Techniques

Much of the work in developing more rapid start-up and shut-down techniques was done by several utility companies. In order to comply with these techniques, steam generator designs had to include the following features:

- Drainability of steam and water surfaces.
- Wide range of steam temperature control.
- Elimination of rolled joints (through use of all welded construction).

h. Welded Panel-Walls

Perhaps the single most dramatic development of the second half of the century was the welded panel-wall. The panels consist of a number of tubes joined together by a process of fusion welding. The tubes are spaced about three-eights to one-half inches apart by means of bars, which are then fused to the tubes to form a continuous metal furnace lining as shown in Figure B-2. The first commercial installations having welded furnace walls went into service in 1953 (Ref. B-11 and -12) and 1955 (Ref. B-13).

Panel-wall construction, accomplished in the shop with rigorous quality control, has led to considerable design simplification, improved techniques of field erection, and significant cost savings. This type of construction eliminated the need for an inner furnace casing since the welded wall forms its own casing, as shown in Figure B-3. Membrane or fin-tube walls, as they are also called, made possible the economic utilization of supercritical forced circulation and pressurized combustion. The advantages of welded waterwalls and radiant superheaters were combined by relocating radiant superheaters as full length or partial division walls.

A generation of units also appeared (Ref. B-14) in which radiant superheaters comprised the walls of the furnace. The tubes of these sections can have tube metal temperatures of up to 1000°F. It has been shown that in burning refuse, corrosion may well occur at tube metal temperatures of 750°F and above. Thus steam generators of this type may not readily lend themselves to modification for the purpose of refuse burning.

i. Excursion into the High Pressure Domain

During the 1950's, when only a few of the largest units within power plants exceeded 300 MW, it was predicted by even optimistic observers that unit size (power capacity) had reached a plateau

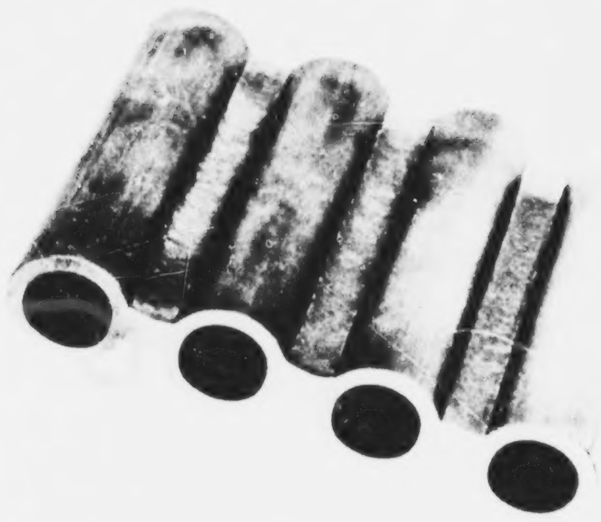


FIGURE B-2. SECTION OF WELDED PANEL-WALL

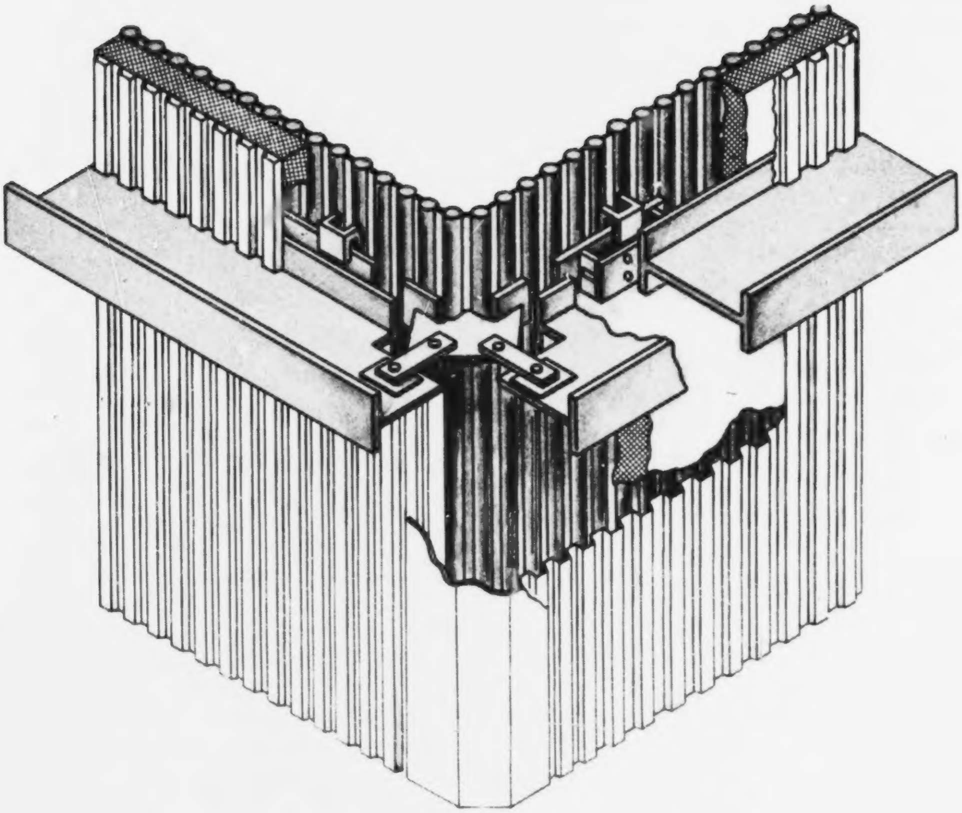


FIGURE B-3. TYPICAL EMPLACEMENT OF WELDED PANEL-WALL beyond which few utilities would venture. Instead, it was suggested that the heat-rate gain available from operating at increased pressure and temperature would far outweigh the advantages of mere size expansion. An excursion thus began into the construction of units operating at steam temperatures of 1050-1100°F and above (Ref. B-15). Such plants were the Kearny, Bergen, and Mercer Generating Stations, which operated at steam conditions of 2400 psig/1100°F/1050°F. Special interest was attached to two units of this era because the steam pressure approached 5000 psig. One unit of 125 MW was at the Philo Station (start-up March 1957) with steam conditions of 4500 psig/1150°F with a double reheat to 1050°F and 1000°F. The other was the Eddystone Station (start-up 1959) with two units having steam conditions of 5000 psig/1200°F with a double reheat to 1050°F. In Germany, where once-through design had been in use only for sub-critical pressures, the first supercritical unit was a unit of 85 MW at the Huels Chemical Works (start-up November 1956), having steam conditions of 4520 psig/1112°F with a double reheat to 1040°F (Refs. B-16 and -17).

These breakthroughs into high pressures and temperatures proved, however, to be only excursions. Today, even though supercritical pressures in the 3600-3675 psig range have become commonplace, they are matched by steam temperatures which rarely exceed 1000°F. Furthermore, the predicted leveling off of unit size did not eventuate. By 1966, more than half the generating capacity on order was to be produced by units of 500 MW and above.

What had occurred during the preceding decade was a reappraisal of the relationship between unit and plant size, and total system load. The arguments favoring the development of larger units were: (1) a reduction in generating costs; (2) the development of widespread utility system interconnections; and (3) a slight increase in efficiency*. The principal factors that implemented the trend to greater unit-size were the advances previously described. Of these, the most significant were the use of welded walls for enclosing the combustion zone and the availability of superior materials for use in the superheater and reheater tubes, the most critical heat absorbing surfaces in modern boilers. The choice of alloys for these sections has centered on chromium-molybdenum, with austenitic steels being favored in the finishing sections (Ref. B-15). Rapid advancements in steam generator, turbine, and accessory equipment sizes also supported the trend towards larger units (Ref. B-18).

A case history demonstrating this trend is the experience of the American Electric Power Company. The success of Philo 6, first operated in 1957, promoted it as the prototype for supercritical pressure and double-reheat units. Two 475 MW supercritical units at Breed and Philip Sporn 5 were first operated in 1960. The sound operation of these units, and the solution of a number of lesser problems that arose, gave confidence to the direction taken. Tanners Creek, first operated in 1964, was a 600 MW unit. Cardinal 1 and 2 were again 600 MW units, but incorporated two significant changes. These represented the move from cyclone, wet bottom firing at Tanners Creek to pulverized-coal, dry-bottom firing at Cardinal, and from an 1800 rpm, four-flow, low pressure section at Tanners Creek to a 3600 rpm six-flow arrangement at Cardinal (Ref. B-19). Big Sandy 2 was an 800 MW unit, which represents a 33% increase in size over Cardinal (Refs. B-20 to -22). These units were duplicated at Mitchell 1 and 2, and Amos 1 and 2. New orders were recently placed for 1200 MW units. The size-leap of this decade has also resulted in the order for two 1300 MW units for the Cumberland Steam Plant of the Tennessee Valley Authority (Ref. B-23). According to recent predictions, this trend in unit-size increase will continue such that the maximum size unit installed in 1987 will be 3000 MW (Ref. B-24). This same trend has also been the experience of other countries, notably the United Kingdom (Refs. B-25 to -28).

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*An increase from 300 to 1000 MW results in a reduction in heat rate of 1/2 to 1 percent.

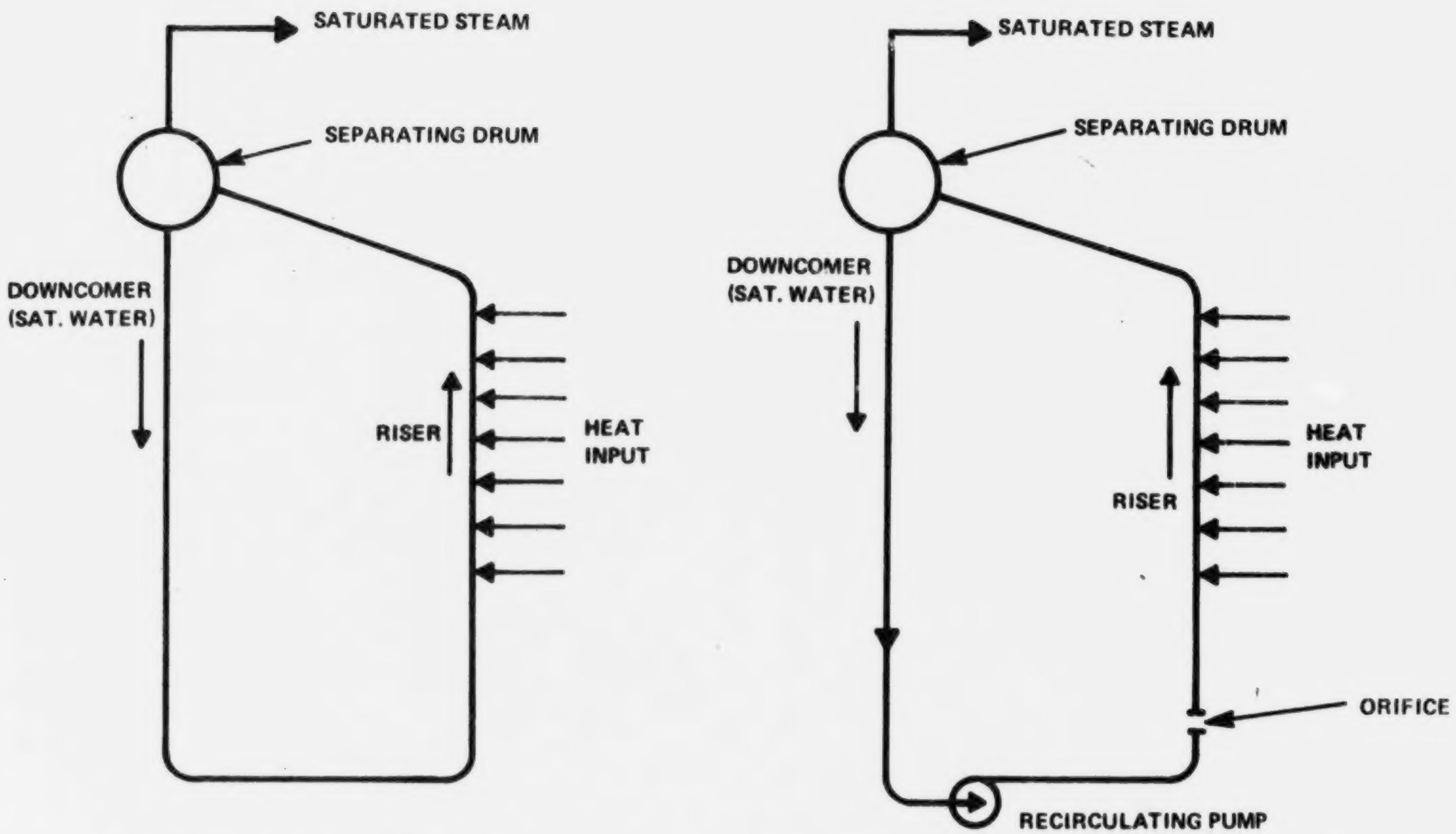
2. Steam Generator Design

a. Basic Circulation Effects

In the natural circulation steam generator, the pumping head is provided by the density difference between the saturated liquid in the unheated downcomer and the steam-water mixture in the heated risers, as shown in Figure B-4A. A separating drum is required to provide the recirculated saturated liquid to the unheated downcomers and saturated steam to the superheat inlet. Inherently, this unit has been proved to be suited only for subcritical pressures and generally is operated at or below 2850 psig (Ref. B-29).

In controlled circulation (Figure B-4B), a recirculating pump is employed to insure sufficient pumping head for the proper cooling of furnace circuits. As the pressure approaches the critical pressure of 3206 psia, the difference in density between water and steam is reduced (as shown in Figure B-5) to a point where natural recirculation is impossible; a mechanical means of fluid circulation, such as a pump, is then required (Ref. B-30).

The forced circulation or "once-through" design is European in origin; its general application and use in the United States is comparatively recent (Ref. B-31). A unit is generally considered once-through if it does not employ recirculation at full load. A highly simplified representation of the once-through principle is given in Figure B-6. Typical boiler fluid temperatures are shown in Figure B-7. The three basic configurations of once-through steam generators are shown in a simplified form in Figure B-8.


SATURATED STEAM
SEPARATING DRUM
DOWNCOMER (SAT. WATER)
RISER
HEAT INPUT
SATURATED STEAM
SEPARATING DRUM
DOWNCOMER (SAT. WATER)
RISER
HEAT INPUT
ORIFICE
RECIRCULATING PUMP

A: NATURAL CIRCULATION

B: CONTROLLED CIRCULATION

FIGURE B-4. BASIC CIRCUITS FOR ACHIEVING RECIRCULATION AT FULL LOAD

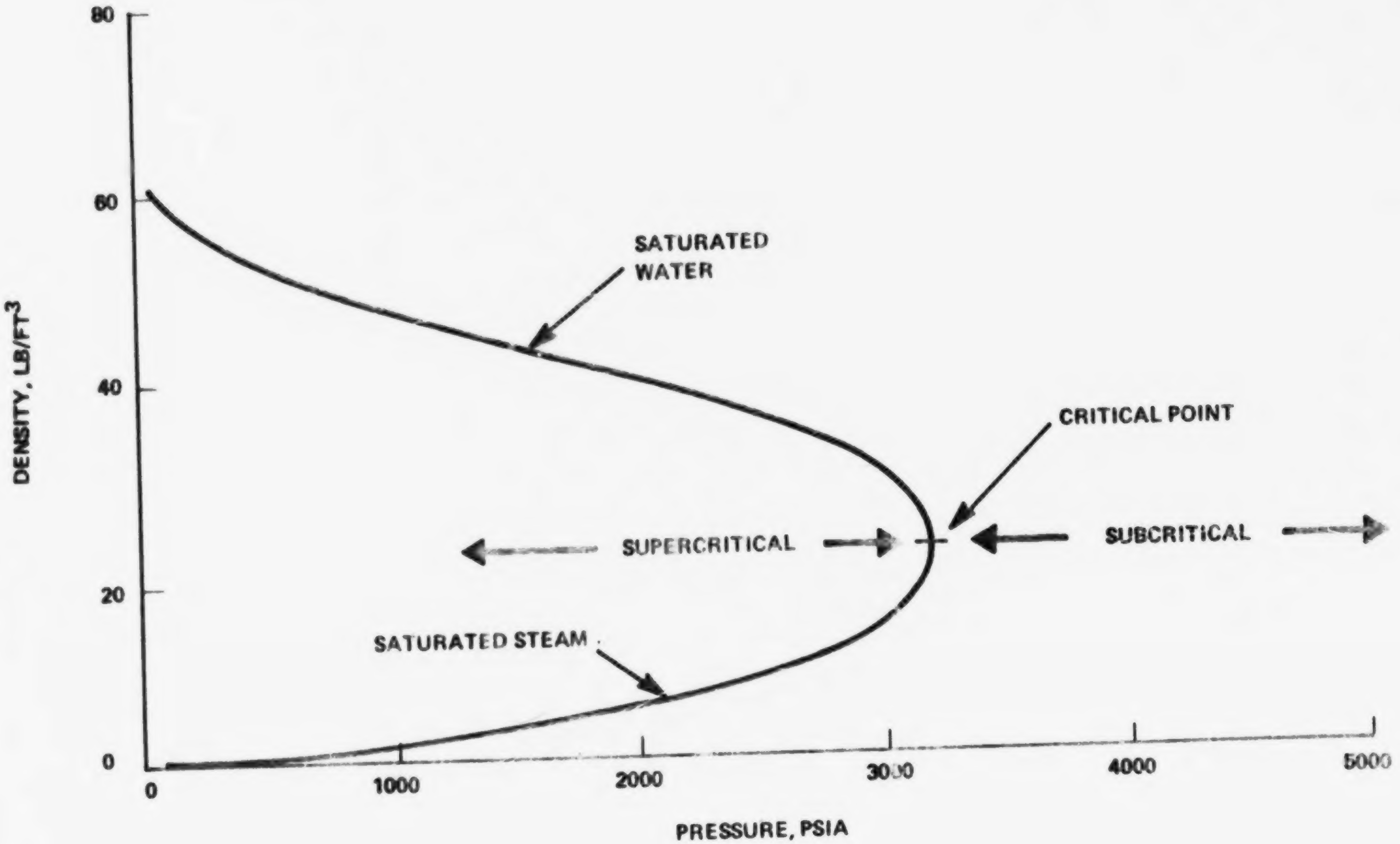


FIGURE B-5. EFFECT OF PRESSURE ON DENSITY OF STEAM AND WATER

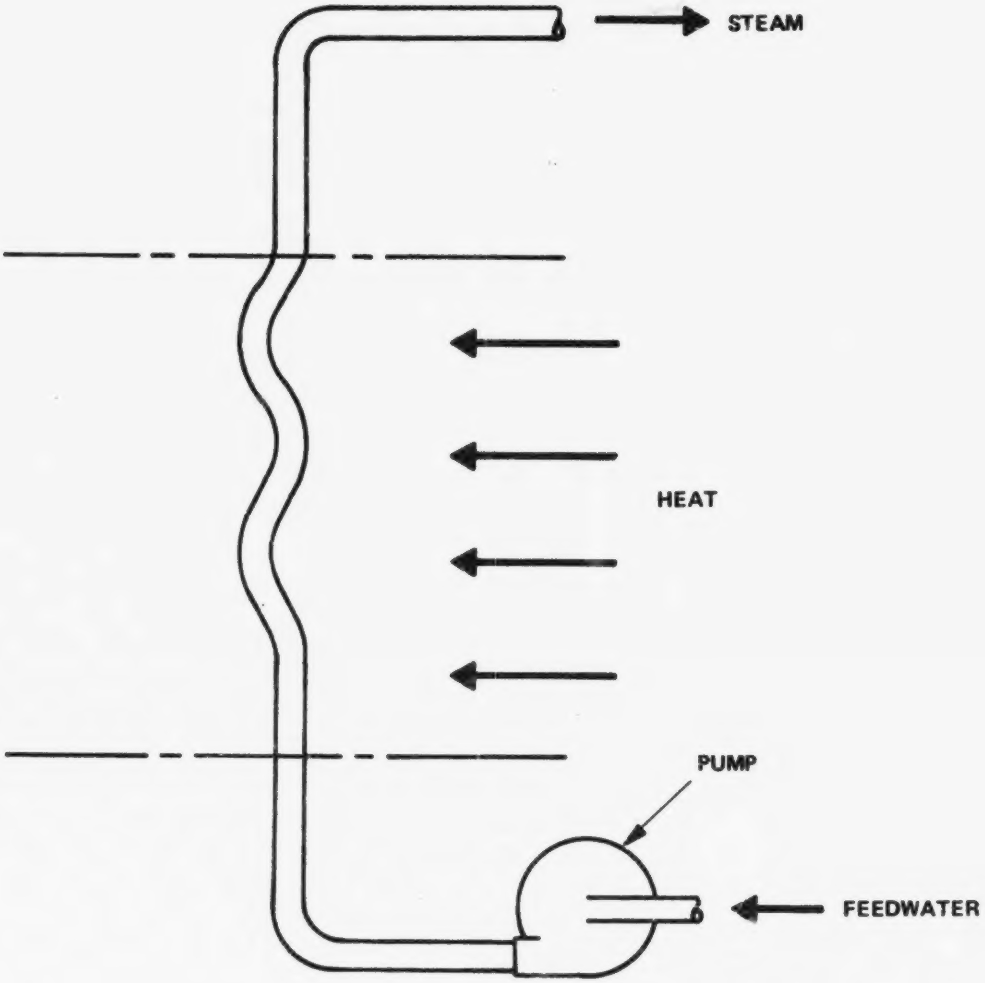

STEAM
HEAT
PUMP
FEEDWATER

FIGURE B-6. PRINCIPLE OF ONCE-THROUGH STEAM GENERATOR

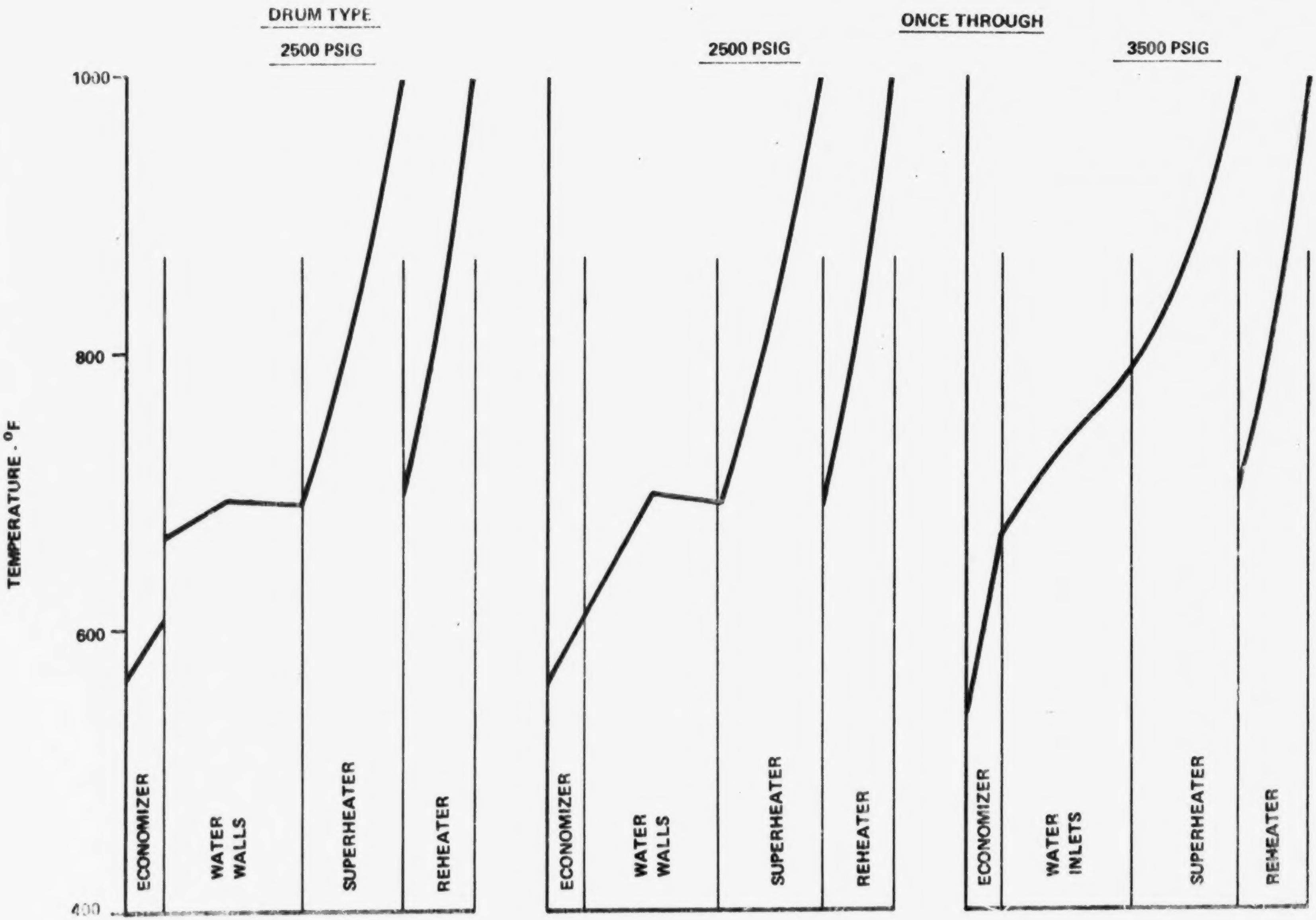
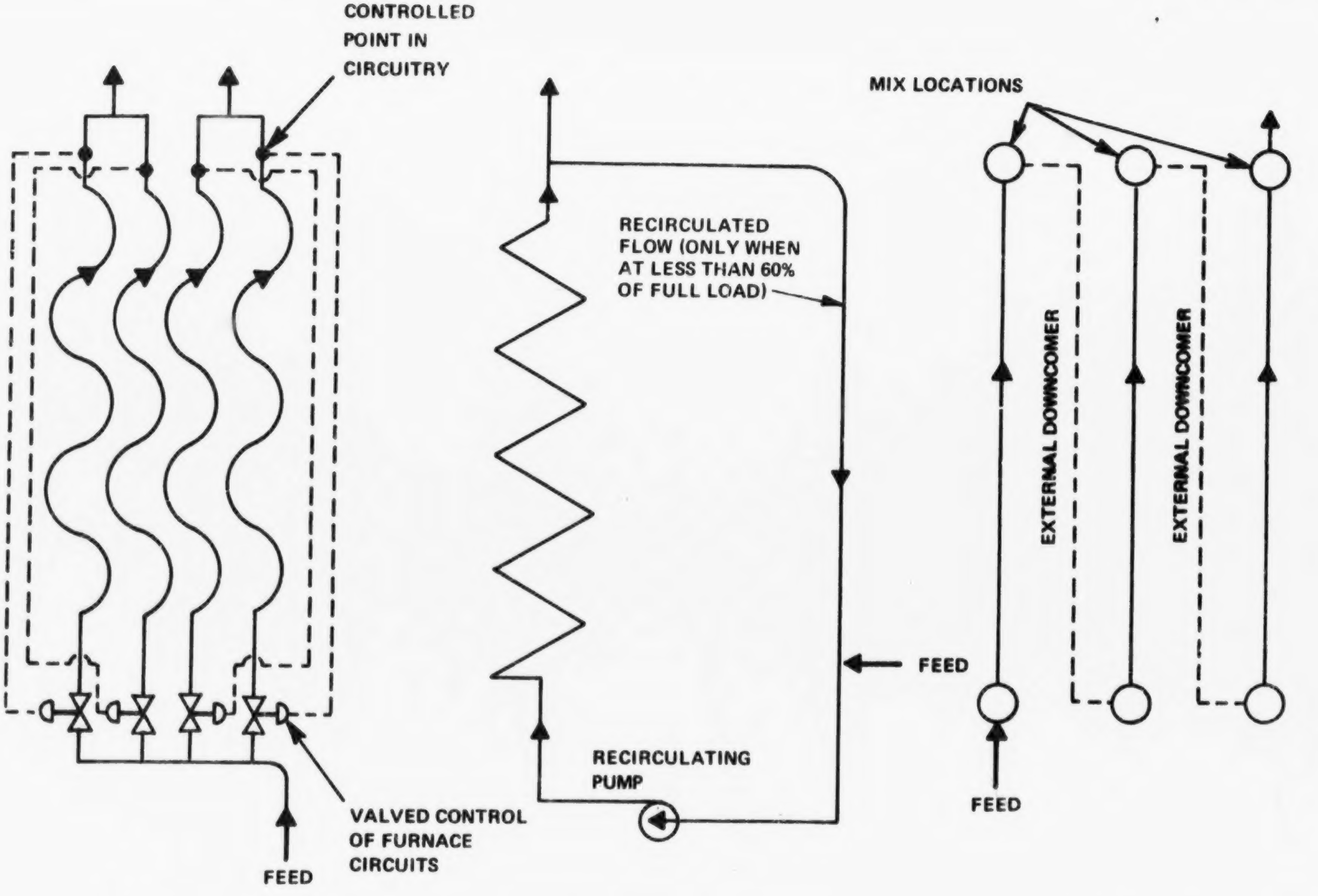


FIGURE B-7. TYPICAL BOILER FLUID TEMPERATURES


CONTROLLED POINT IN CIRCUITRY
VALVED CONTROL OF FURNACE CIRCUITS
FEED
RECIRCULATED FLOW (ONLY WHEN AT LESS THAN 60% OF FULL LOAD)
FEED
RECIRCULATING PUMP
MIX LOCATIONS
EXTERNAL DOWNCOMER
EXTERNAL DOWNCOMER
FEED

SULZER DESIGN

COMBINED CIRCULATION DESIGN

BENSON DESIGN

FIGURE B-8. ONCE-THROUGH BOILER SYSTEMS

The Sulzer design is primarily a once-through unit that provides a fixed point in the fluid circuitry for blow-down or control. It may be designed to operate either in the subcritical or supercritical region. The subcritical design utilizes a steam-separating system fixed at a point where the entering fluid is 95 percent steam. The separated liquid is treated as blow-down and is fed back to the external pre-boiler cycle. In the supercritical design, a transitional zone is required where circuit temperatures can be monitored and controlled so that maximum design values are not exceeded. Each of these designs employs "valved" furnace-circuitry and a control system to proportion fluid to the circuits, as shown in Figure B-9.

The combined-circulation design employs a fluid recirculating-pump for low-load operation of the furnace. Basically, this design is a Benson type circuitry modified by incorporating a recirculating loop and pump. Up to approximately 60% of load, the recirculated- and throughput-fluid is used to cool furnace circuits; from this point to full load, once-through operation of the furnace circuits is used.

The Benson once-through design for either subcritical or supercritical operation is characterized by the complete absence of any steam separating drums or fluid recirculation. Feedwater is continually heated to final outlet steam temperature in a single continuous flow-path. The difference between subcritical and supercritical Benson designs is the arrangement of the circuits. Figure B-10 shows the arrangement of the circuits for a subcritical and Figure B-11 for a supercritical system.

It will be noted that the basic circuitry consists of heater upflow tubes and unheated downcomers as in natural circulation systems. The main difference between the two is the circuitry within the furnace. For the greater pressures of supercritical once-through designs, smaller size tubes are used. However, the disadvantage of using a greater number of tubes is compensated for by an increase in the allowable heat absorption.

Present designs of natural circulation and once-through boilers have evolved to a point of standardization that the structural supports setting and insulation, and external appurtenances, as shown in Figure B-12, are now quite similar.

Although the various forced-circulation systems were employed in Europe earlier than in the United States, it must be pointed out that European unit-sizes and steam-cycles were quite different from those used by the United States central-station industry. In addition, many aspects of boiler design, particularly those relating to furnace wall-enclosures, were based on markedly different concepts. In Europe, tube-systems were tied

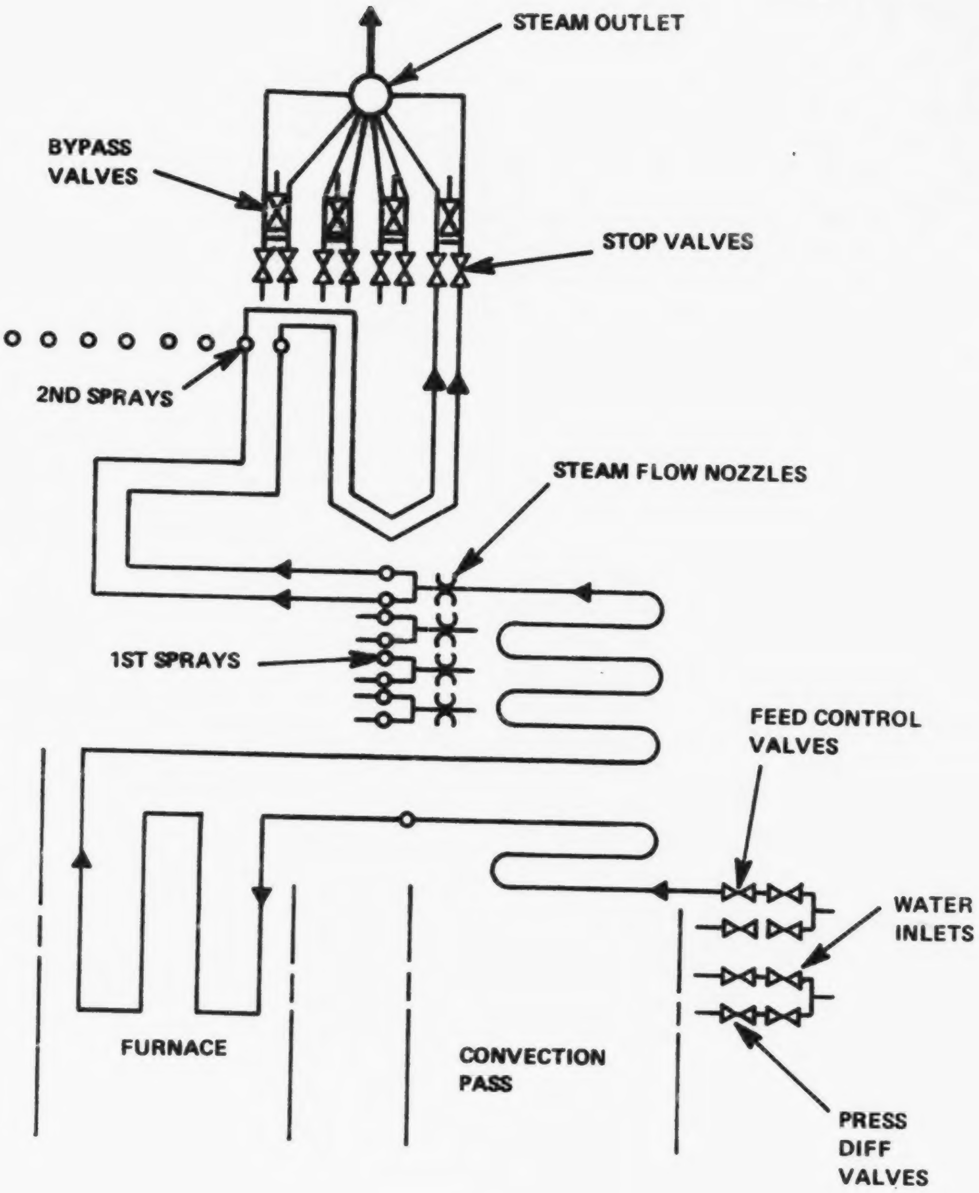

STEAM OUTLET
BYPASS VALVES
STOP VALVES
2ND SPRAYS
STEAM FLOW NOZZLES
1ST SPRAYS
FEED CONTROL VALVES
WATER INLETS
FURNACE
CONVECTION PASS
PRESS DIFF VALVES

FIGURE B-9. SULZER ONCE-THROUGH STEAM GENERATOR

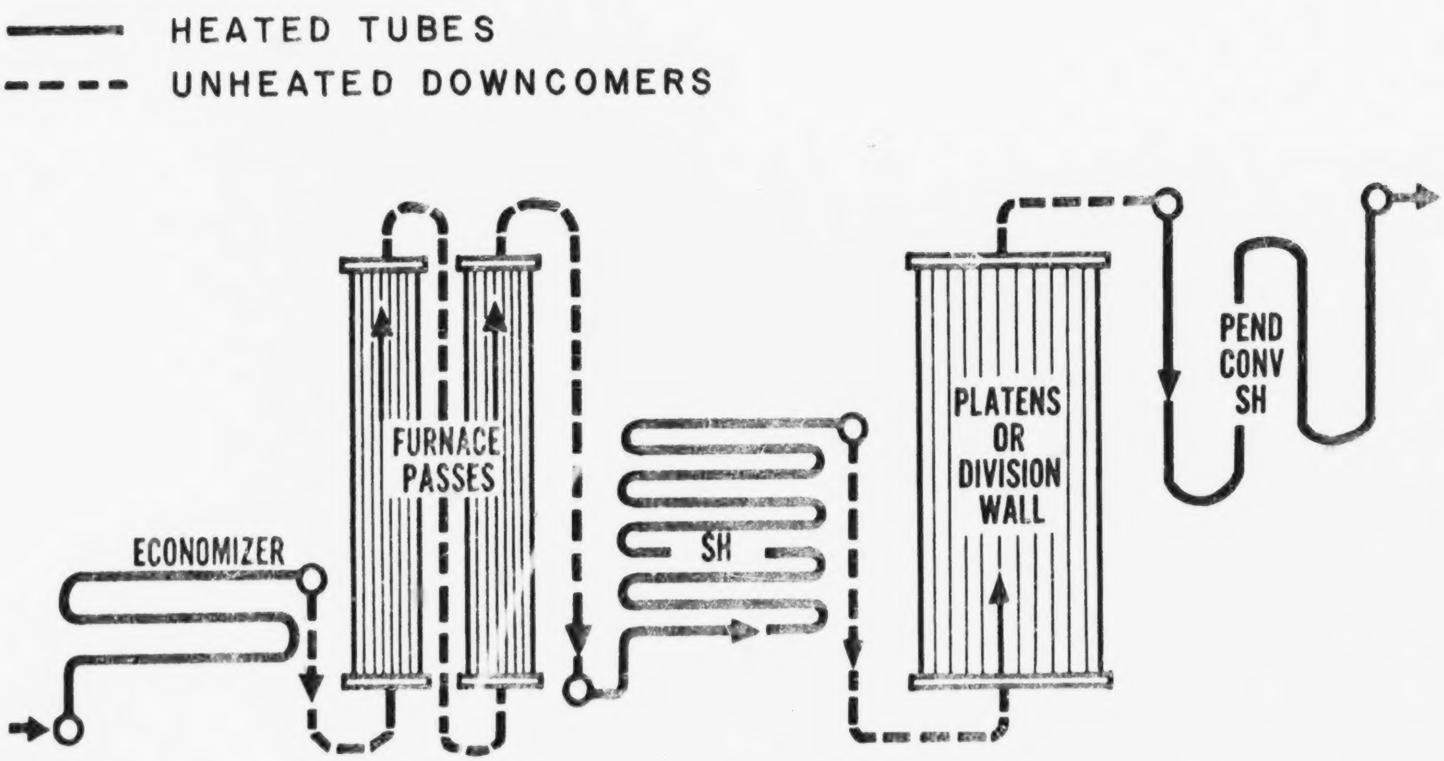

HEATED TUBES
UNHEATED DOWNCOMERS
ECONOMIZER
FURNACE PASSES
SH
PLATENS OR DIVISION WALL
PEND CONV SH

FIGURE B-10. BENSON CIRCUITRY FOR SUBCRITICAL SERVICE

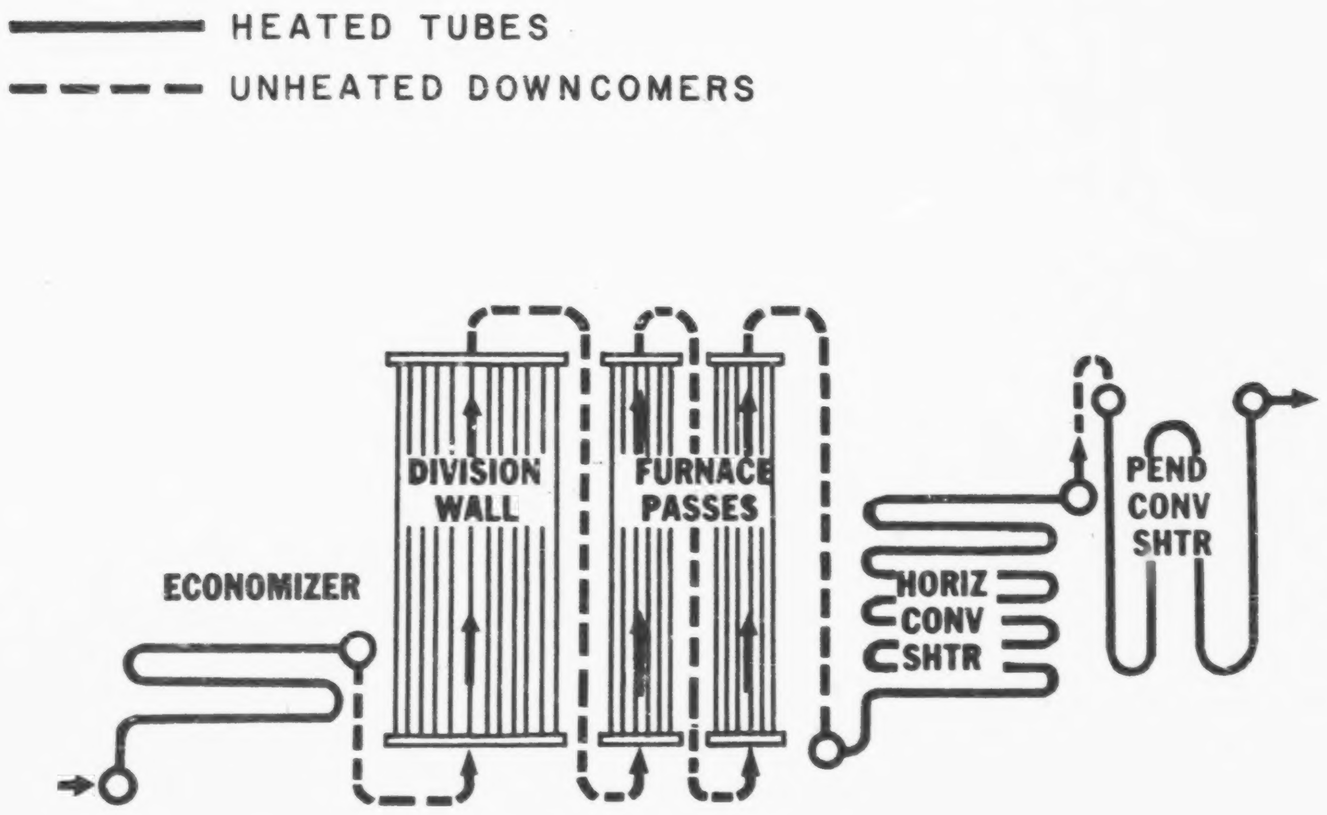

HEATED TUBES
UNHEATED DOWNCOMERS
ECONOMIZER
DIVISION WALL
FURNACE PASSES
HORIZ CONV SHTR
PEND CONV SHTR

FIGURE B-11. BENSON CIRCUITRY FOR SUPERCRITICAL SERVICE

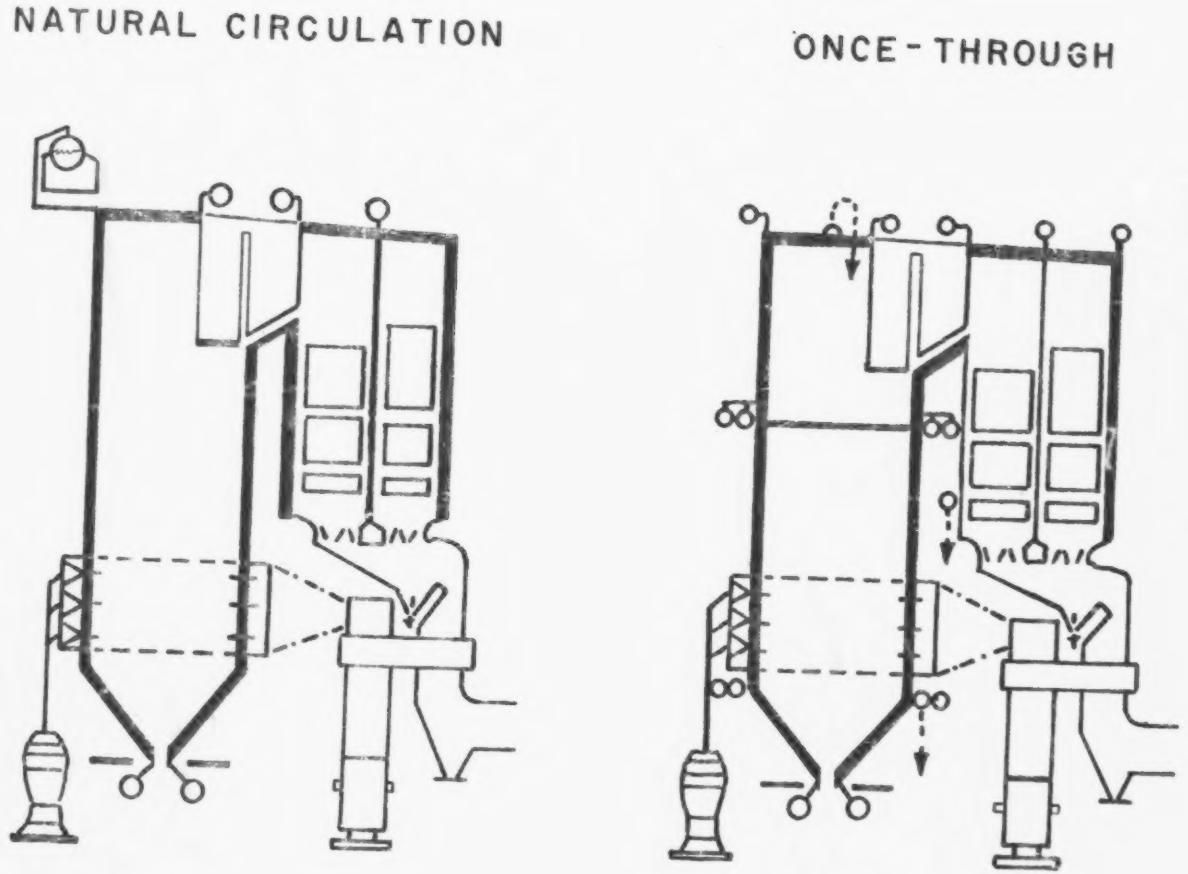

NATURAL CIRCULATION
ONCE-THROUGH

FIGURE B-12. STRUCTURAL SIMILARITIES OF MODERN BOILERS OPERATING BY DIFFERENT PROCESSES back through the brick to the steel supporting-structure and were designed to move (in response to thermal variations) relative to the surrounding brick wall. Because of this comparative freedom for expansion of tube systems, circuits could be and were designed with highly individual shapes and functions. The various types of basic "meandering" tube arrangements are shown schematically in Figure B-13 and a typical furnace arrangement is shown in Figure B-14. Both the Sulzer and Benson boilers employ such tube arrangements in the high absorption areas of the furnace.

While these forced-circulation units became rather common in Europe, their late application in the United States was more a matter of economics than technology. Here again, the welded-wall construction was a major factor for the adoption of forced-circulation in the United States and for not using the European "meandering" tube-arrangements.

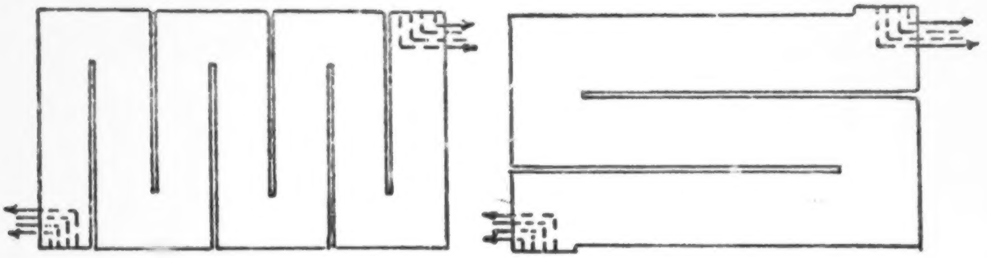
German power station practice is characterized by wide use of the Benson and Sulzer cycles, lower-grade fuels, and slag-tap furnaces. Meandering furnace-tubes allow variable pressure operation and German utilities consider this superior to constant pressure operation as practiced in the United States. The majority of thermal power plants in Germany are limited with respect to space and water resources. Because of these limitations the plants must resort to recirculation of cooling water and cooling towers are more widely used than in the United States.

b. Typical Design Characteristics

Most of the boilers of interest to this study are of the natural-circulation type. In terms of size, units in the nominal range of 50 - 100 MW can be considered small. This size of unit finds application in large industrial plants and small utility or municipal power stations. Final steam temperatures ranging from 700° to 1000°F and operating pressures ranging from 600 to 1800 psig are typical for this category. Steamflows are of the order of 500,000 to 1,000,000 lb/hr. Figure B-15 shows the arrangement of boiler equipment in a unit in this size range operating at steam conditions of 1500 psig and 1000°F. It is noted that only 29% of the total heat absorbed by the generator is required for superheating the steam. Units near the 100 MW size may have reheaters.

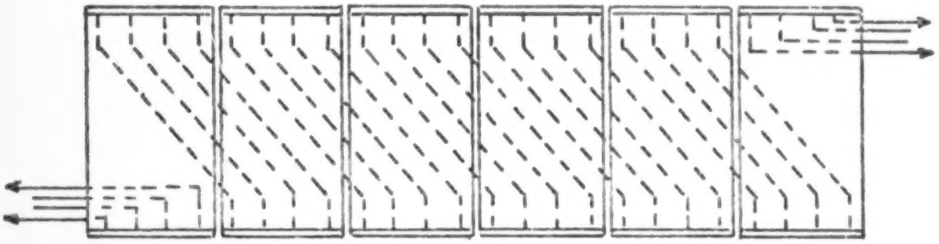
The furnace is completely water-cooled. The superheater is of the all-convection type and is divided into two or more sections. Temperature control is accomplished by water spraying between sections of the superheater. The economizer is located in the heat recovery area, immediately after the superheater.

This unit is designed with sufficient furnace-volume so that combustion is complete before the gas enters the convection surfaces. The furnace water-cooling surface must have sufficient area to reduce the

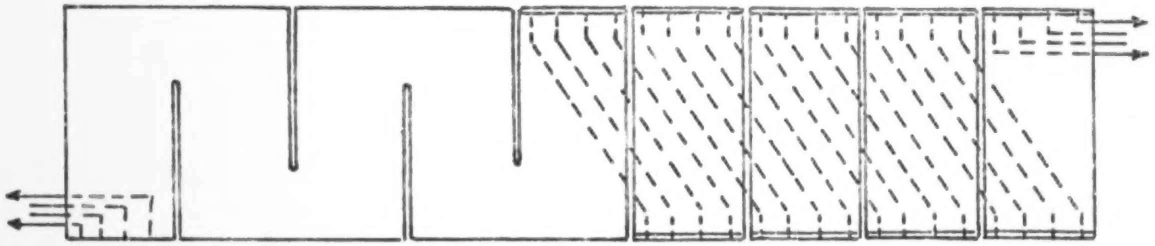


VERTICAL LOOP

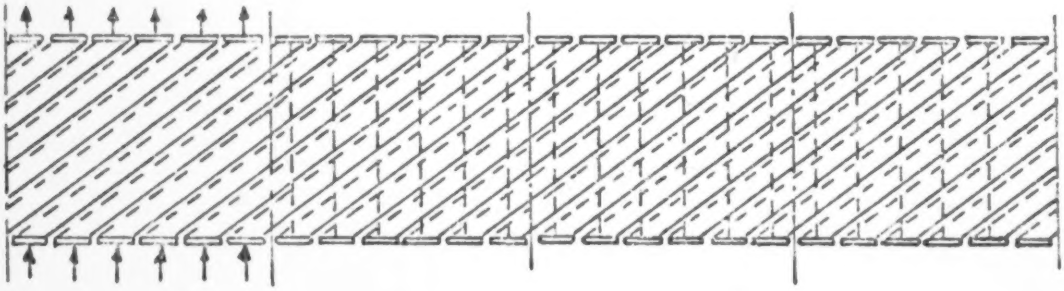
HORIZONTAL LOOP



RISER-DOWNCOMER SYSTEM
SIX SECTIONS WITH 4 DOWNCOMERS EACH

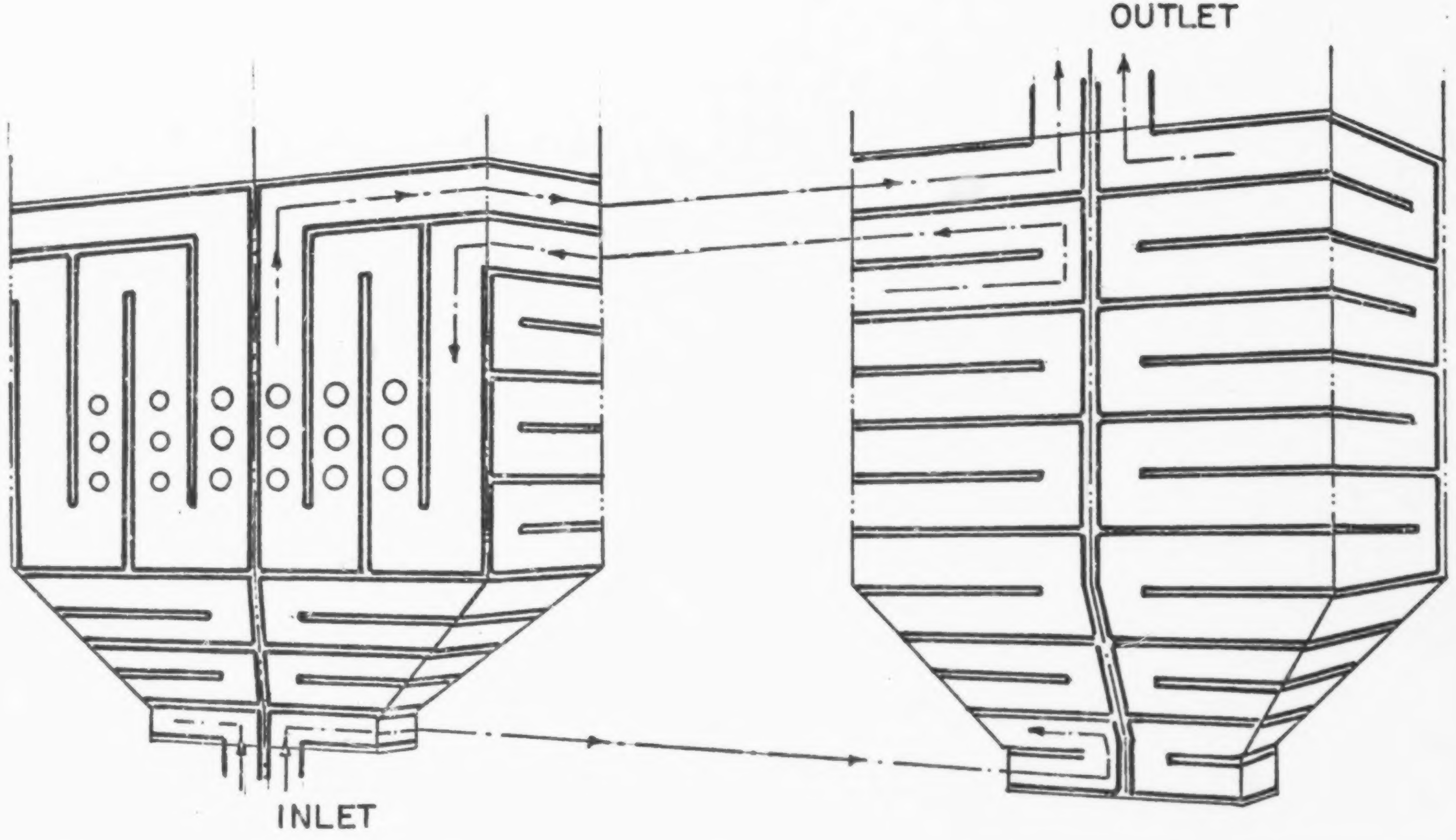


COMBINATION LOOP TYPE AND RISER-DOWNCOMER SYSTEM



PARALLEL RISER-DOWNCOMER SYSTEM

FIGURE B-13. VARIOUS TYPES OF ONCE-THROUGH EVAPORATORS



FRONT WALL AND RIGHT SIDE WALL

REAR WALL AND LEFT SIDE WALL

FIGURE B-14. MEANDER-STRIP EVAPORATOR FOR FRONT WALL FIRING

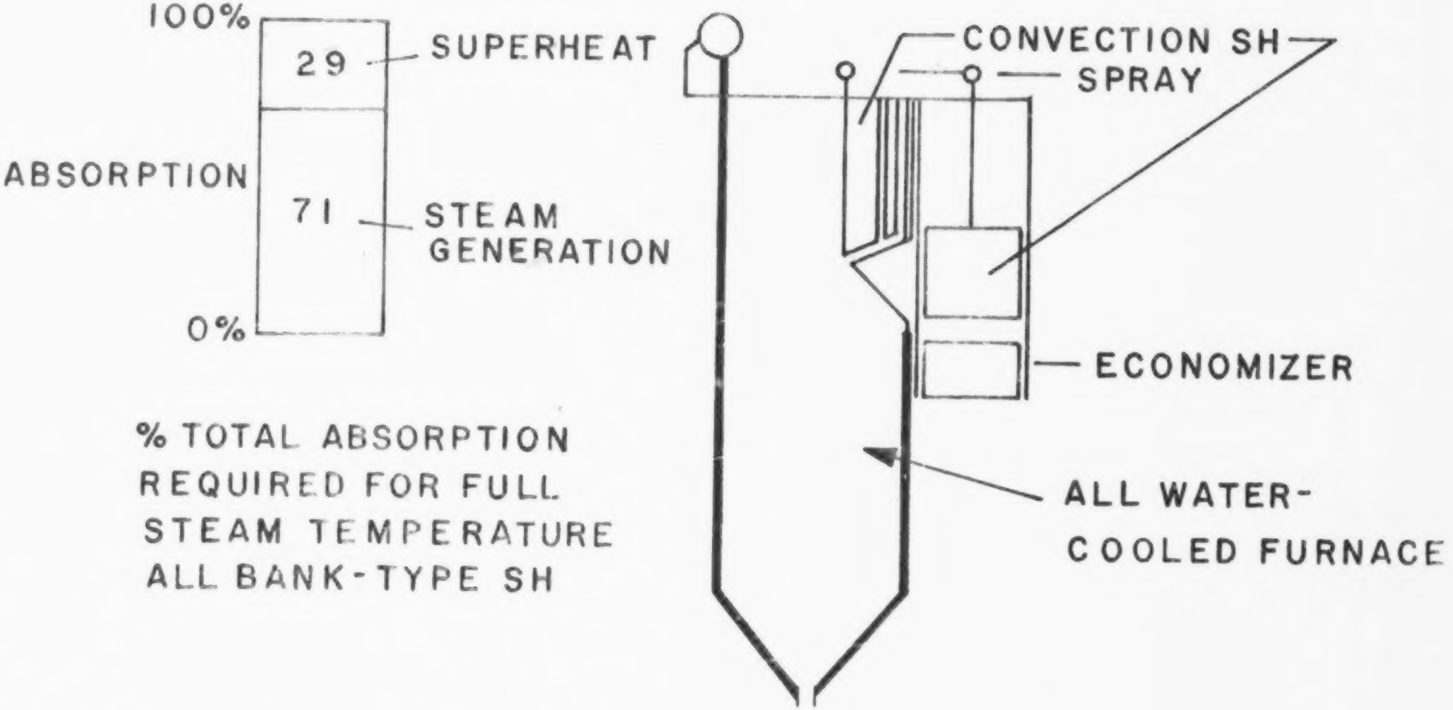

100%
29
SUPERHEAT
ABSORPTION
71
STEAM GENERATION
0%
% TOTAL ABSORPTION REQUIRED FOR FULL STEAM TEMPERATURE ALL BANK-TYPE SH
CONVECTION SH
SPRAY
ECONOMIZER
ALL WATER-COOLED FURNACE

FIGURE B-15. TYPICAL CONFIGURATION OF SMALL (50 - 100 MW) POWER BOILER temperature of the products of combustion below the point at which objectionable slag-accumulations will occur on the convection-surfaces.

The larger units, in the 100-400 MW size, are usually of the reheat type. Figure B-16 illustrates the arrangement of such a unit having steam conditions of 2400 psig /1000°F at the superheater outlet, and 1000°F at the reheater outlet. It will be noted that about half of the total heat absorbed by the unit is required for superheat and reheat. This figure shows a unit designed entirely with convection-type superheater and reheater.

The superheater, which typically consists of several sections, can include a platen for minimizing slagging difficulties, a pendant section in the high gas-temperature zone, and a large bank in a lower temperature zone. The reheater is located between two sections of the superheater to economize on space. The design of a high-pressure reheat unit can be improved by using a radiant superheater in combination with a convection superheater. Figure B-17 shows such an arrangement. It will be noted that, in the radiant superheater, the steam temperature decreases as the steam-flow increases, whereas in the convection superheater gas temperature and mass velocity increase with steam-flow. The combination of the convection and radiant superheaters thus produces a relatively flat steam-temperature characteristic for a wide range of loads. This obviates the need to resort to high furnace exit-gas temperature, excessive desuperheating, gas recirculation, or manipulation of burners to accommodate load variations.

Research and experience have shown that corrosion and oxidation take place in zones where the gas and tube metal temperatures are both high. It is possible to minimize these problems by arranging the surfaces so that the highest metal temperatures are in location of low gas-temperatures and, conversely, low metal-temperatures in location of high gas-temperatures. As shown in Figure B-18, where the numbers on the curve refer to the indicated positions in the boiler, all heating surfaces are located in safe zones. Relatively low-temperature steam flows in the radiant superheater, a zone of high gas-temperature and heat absorption. The higher steam-temperature sections of the superheater and reheater, on the other hand, are located in cooler gas zones.

The relationship between heat release rate and heat absorbed was studied in a program sponsored by the ASME (Ref. B-29). In this program, measurements were taken of furnace-face temperatures of water-wall tubes at points uniformly spaced in the furnace-walls to determine the thermal distribution pattern in the various walls of the furnace. Figure B-19 shows the unfolded elevations of the four walls of a boiler. The average Δt value for the test is indicated at each point of measurement. Isotherms are shown on the various walls to connect points of equal rate of heat absorption at each point in terms of Btu/hr-ft^2 on the

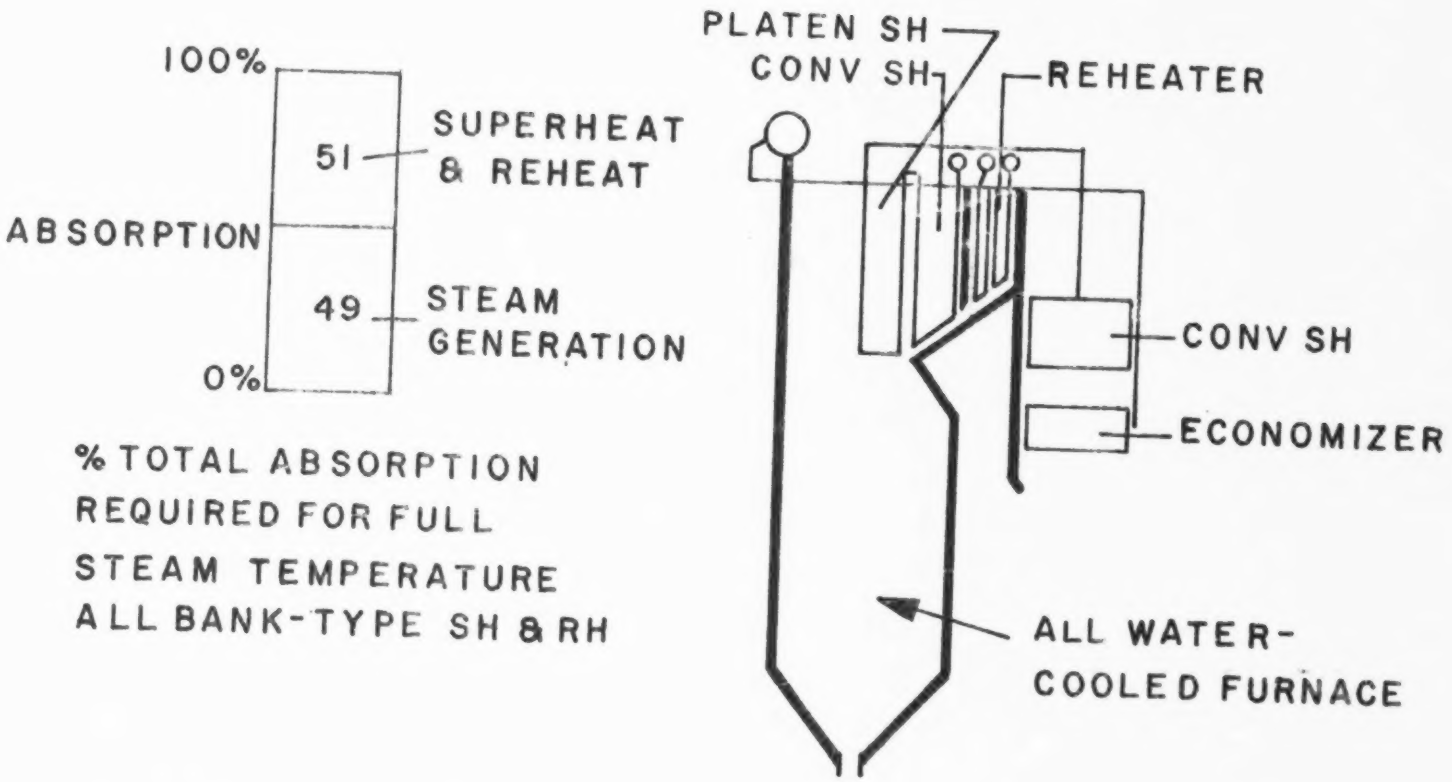

100%
51
SUPERHEAT & REHEAT
ABSORPTION
49
STEAM GENERATION
0%
% TOTAL ABSORPTION REQUIRED FOR FULL STEAM TEMPERATURE
ALL BANK-TYPE SH & RH
PLATEN SH
CONV SH
REHEATER
CONV SH
ECONOMIZER
ALL WATER-COOLED FURNACE

FIGURE B-16. TYPICAL CONFIGURATION OF INTERMEDIATE-TO-LARGE (100-400 MW) POWER BOILER

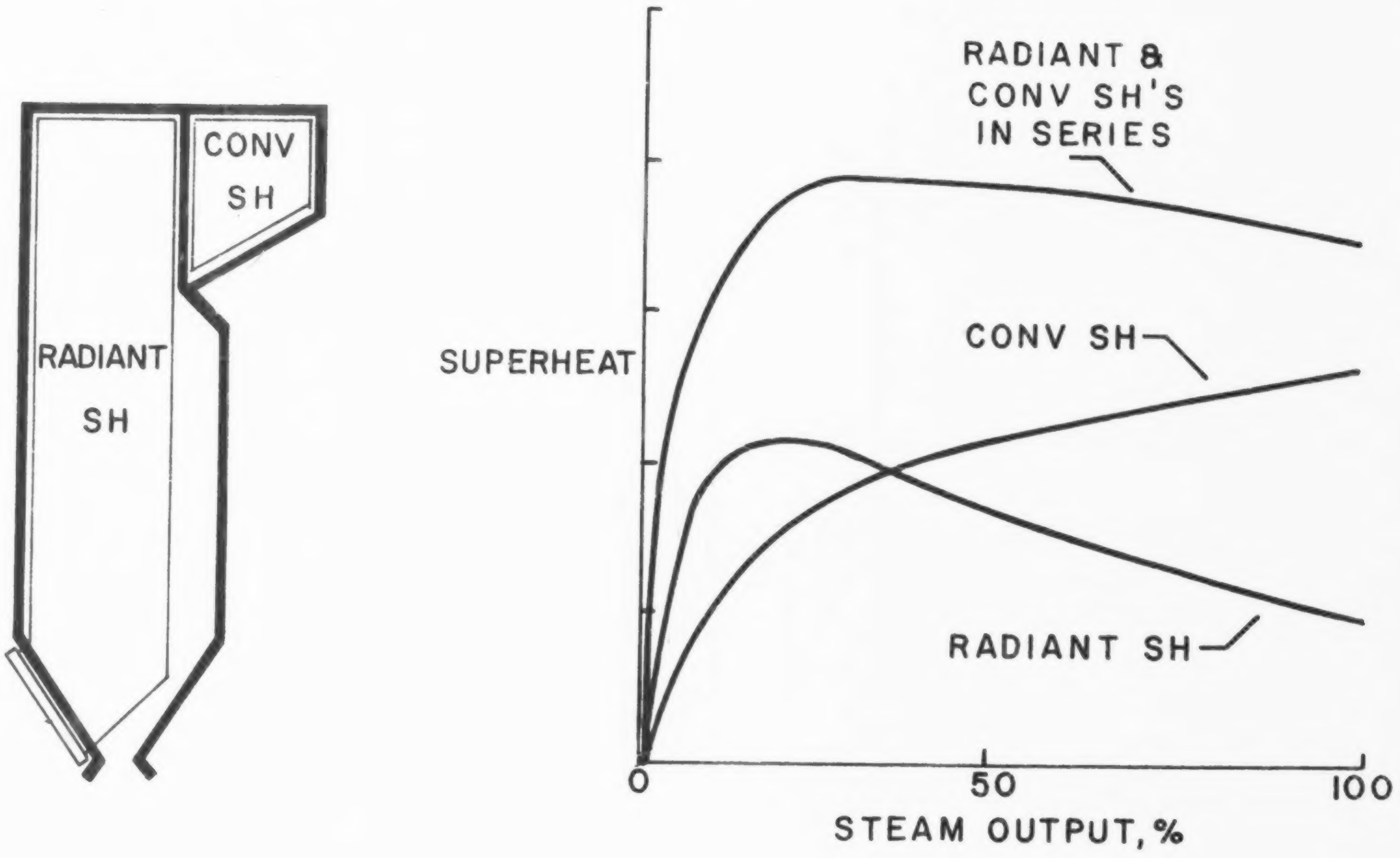


FIGURE B-17. TYPICAL CHARACTERISTICS OF COMBINATION RADIANT AND CONVECTION SUPERHEATERS

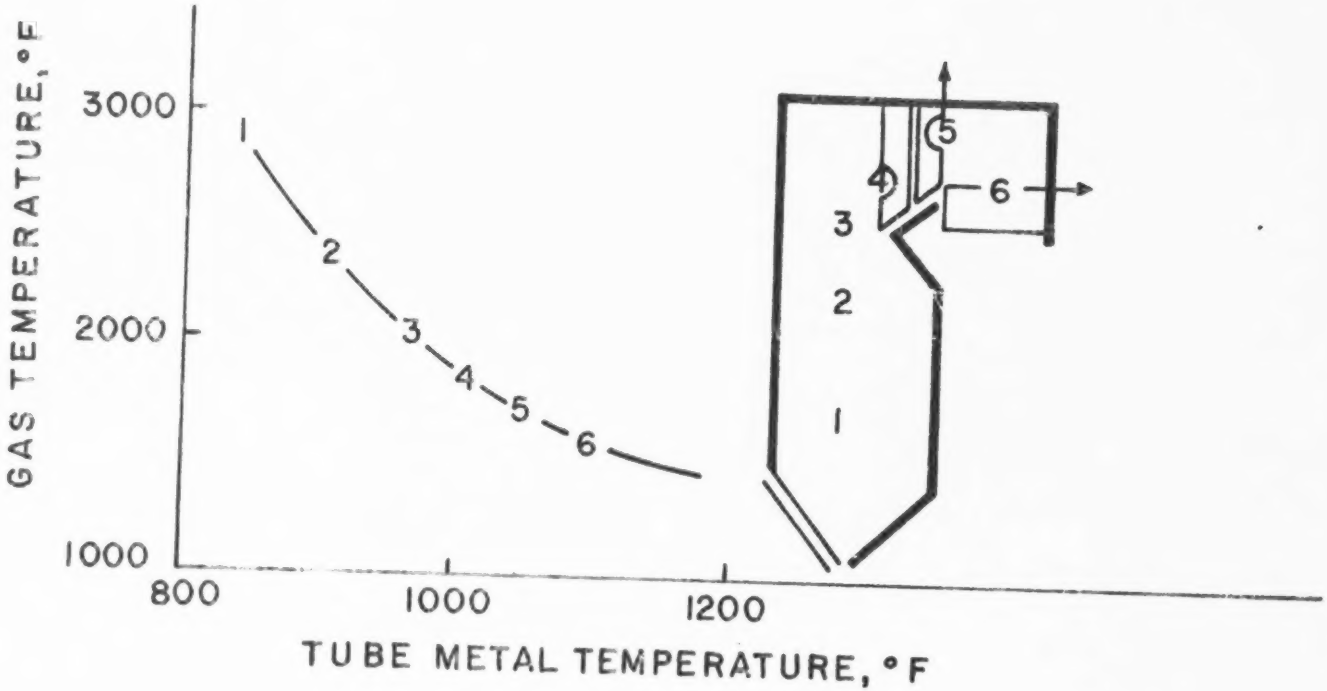


FIGURE B-18. CONSERVATIVE ARRANGEMENT OF HEAT ABSORBING SURFACES

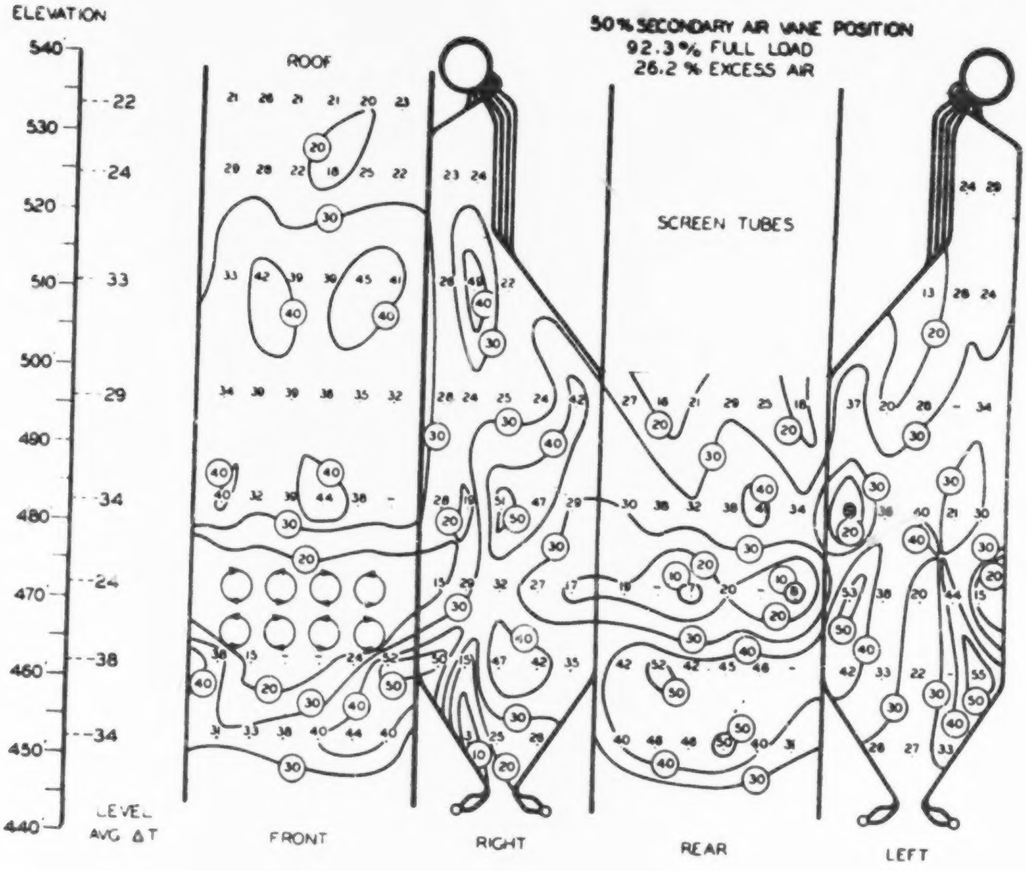

ELEVATION
540
530
520
510
500
490
480
470
460
450
440
22
24
33
29
34
24
38
34
LEVEL AVG ΔT
50% SECONDARY AIR VANE POSITION
92.3% FULL LOAD
26.2% EXCESS AIR
ROOF
SCREEN TUBES
FRONT
RIGHT
REAR
LEFT

FIGURE B-19. FURNACE HEAT ABSORPTION IN STEAM GENERATORS projected area. Figure B-20 is a simplified graph showing heat absorption in the furnace. It illustrates the variation of heat absorption along the length of a radiant tube. It also provides the average absorption used for determining the average performance of the tube, and the maximum absorption used for assigning the metal temperatures to be observed in the selection of tube materials. The shapes of these curves depend on several factors, such as type of firing and location of tubes.

c. Fuel Firing

The physical and chemical characteristics of fuels and their ashes, along with their burning characteristics, are primary factors in determining furnace-type, size, configuration, performance, and detail. Some fuels foul the furnace and heating surfaces. This has an effect on the heat absorption characteristics of the unit and can be of extreme importance when clean and dirty fuels are used alternately. Some fuels, when fired in combination, produce slagging problems that would not exist if each fuel were fired alone. Combination firing also requires appropriate burner design to maintain proper flame clearance and preclude impingement of the flame on the furnace walls.

With coal-fired units, a considerable variation in fuel properties exists. Moisture, ash, other impurities, heating values, and grindability are some of the characteristics of the coal that can influence the boiler design. Being a solid fuel, coal requires a longer residence-time in the furnace than do other fossil fuels to allow the combustion process to go to completion. Residence time is a function of furnace volume and the distance from the burner to the superheater.

The function of fuel-firing equipment is to introduce the fuel and air for combustion, mixing these reactants, igniting the mixture, and distributing the flame and products of combustion. In the pulverized coal-fired system (in the unit size-range under study), the coal is first processed in a crusher and ground to a talc-like powder in a mill. These mills are usually of the low or medium speed type. A typical coal-fired system with a medium speed mill is shown in Figure B-21. For units burning oil and gas, these fuels are delivered to the burners with no intermediate steps other than oil-preheat.

In the burners, the fuel is mixed with the required amount of combustion air and sprayed into the furnace. The design of the burner must be such as to promote a uniform distribution of the hot gas-mass within the combustion chamber. Figure B-22 is a typical design of a multi-fuel burner. Burners are usually mounted on the front and/or rear walls, or in the corners of the furnace. Burners mounted in the corners of the furnace are usually of the tilting type. This aids superheat temperature-control. Each group of burners in a coal-fired unit is associated with a particular mill.

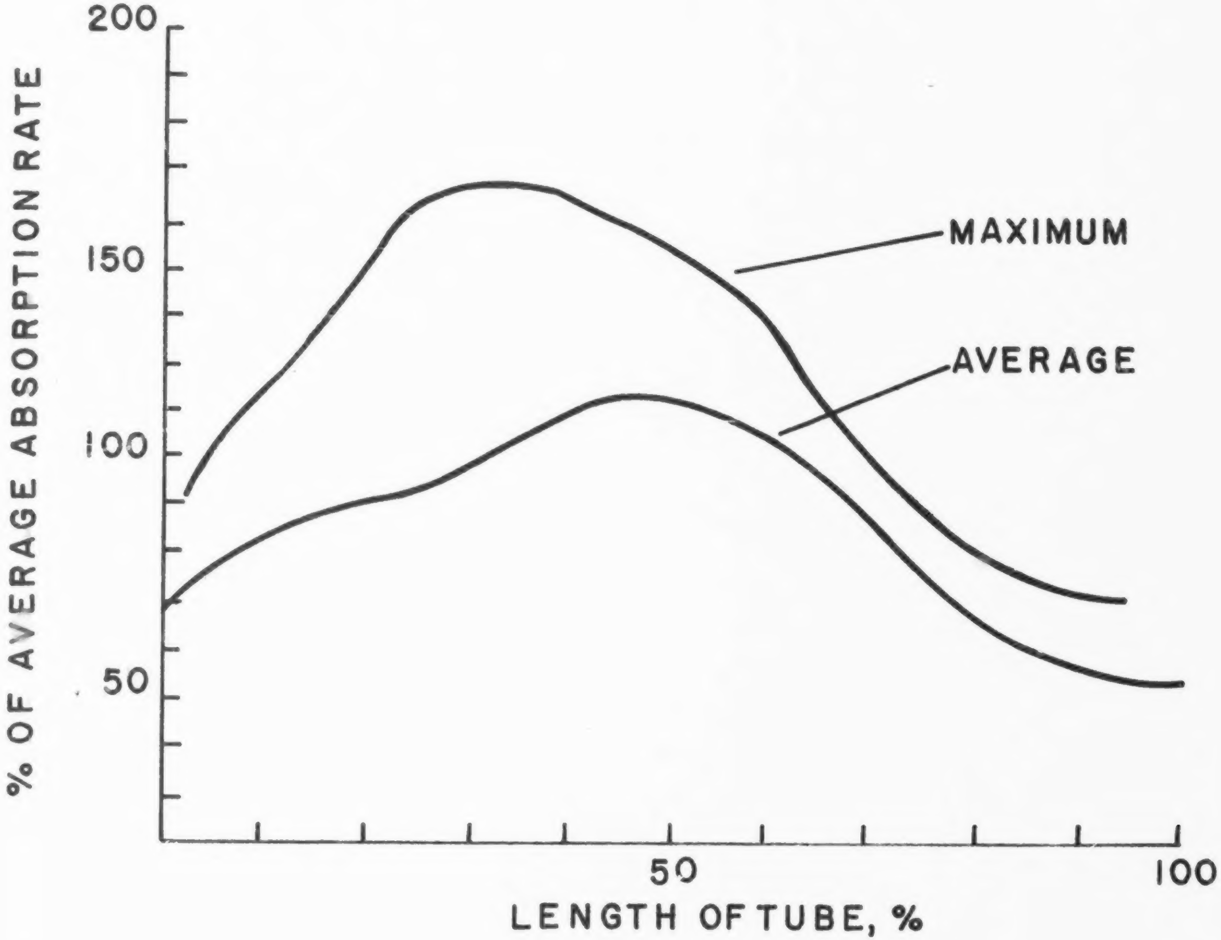


FIGURE B-20. TYPICAL ABSORPTION VARIATION IN RADIANT TUBES

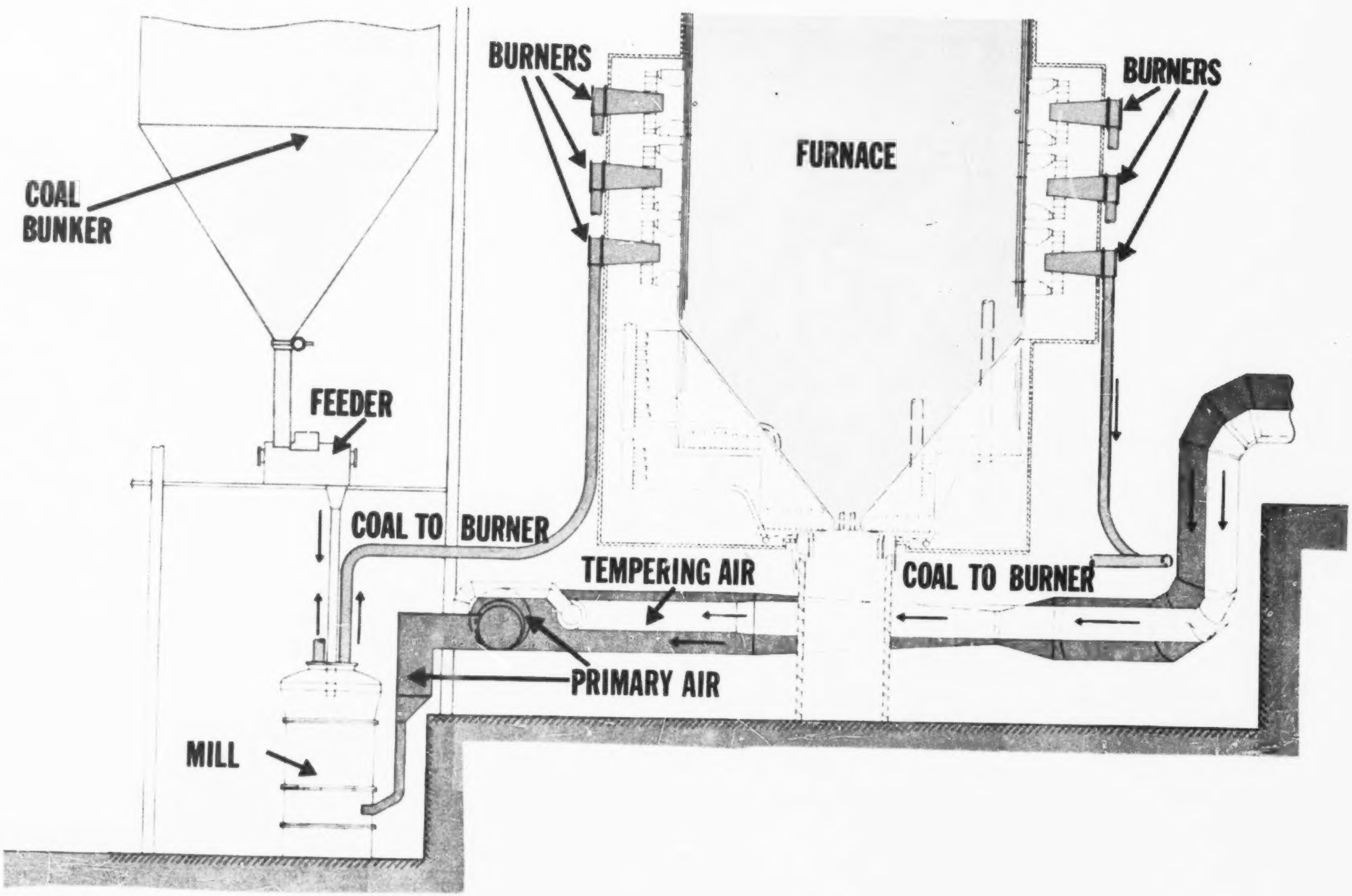

COAL BUNKER
FEEDER
COAL TO BURNER
MILL
BURNERS
FURNACE
BURNERS
TEMPERING AIR
COAL TO BURNER
PRIMARY AIR

FIGURE B-21. PULVERIZER FIRING SYSTEM

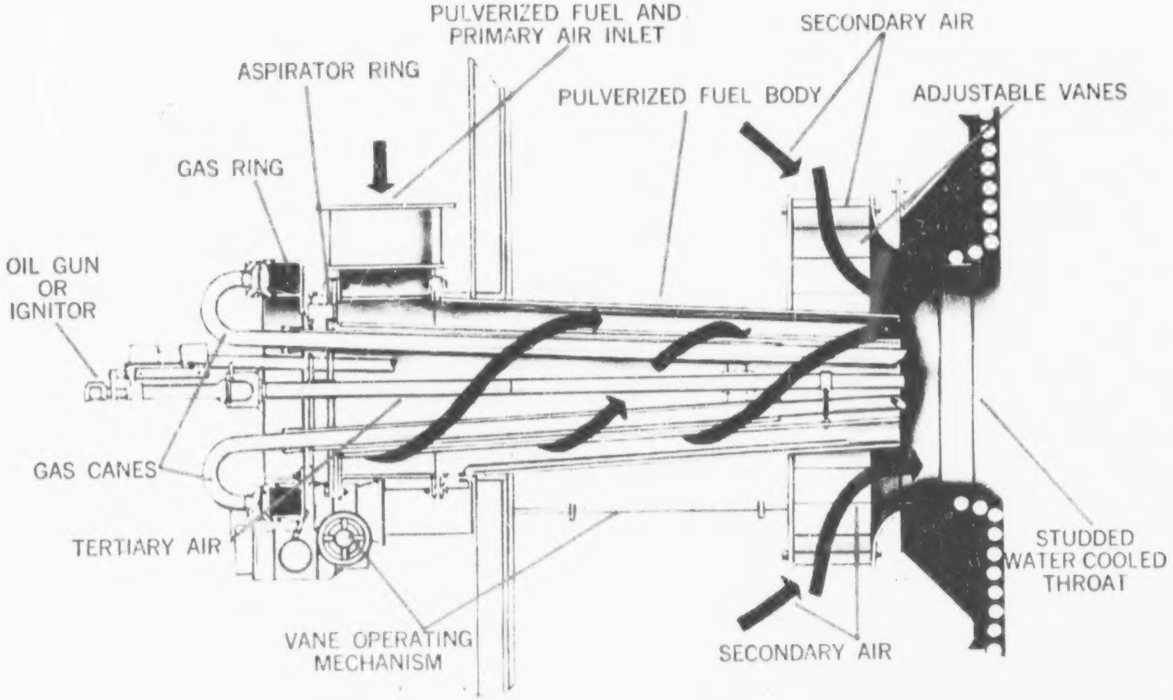

PULVERIZED FUEL AND
PRIMARY AIR INLET
SECONDARY AIR
ASPIRATOR RING
PULVERIZED FUEL BODY
ADJUSTABLE VANES
GAS RING
OIL GUN
OR
IGNITOR
GAS CANES
TERTIARY AIR
STUDDED
WATER COOLED
THROAT
VANE OPERATING
MECHANISM
SECONDARY AIR

FIGURE B-22. MULTI-FUEL BURNER

Cyclone-burner firing is a method used with suitable coals, usually of the low-fusion, high-ash bituminous type. This furnace, as shown in Figure B-23, has a water-cooled, horizontal cylinder in which fuel is fired and combustion is completed. The crushed coal, approximately 95% of which is sized at 1/4 in. or less, is burned at very high heat release rates (500,000 Btu/ft^3-hr); gas temperatures of 3,000°F and higher are developed (Ref. B-32). Basically, this is a slagging furnace.

The case for a dry-bottom or a wet-bottom (slagging) furnace has been a matter of operator preference. In the 1940's, several units in Ohio were built that fired bituminous coal through intertube burners (Ref. B-33). Except for units equipped with cyclone units, no large slagging-furnaces were then built until the 1950's, when a pair of 300 MW units, each with twin furnaces, were ordered. Another pair of similar, but slightly larger, units were put into service in 1960 at the Mercer Generating Station. In both plants the coal was pulverized and fired through the front wall.

In comparison to dry bottom furnaces, it has been shown that slagging-furnaces have demonstrated lower availability and higher maintenance costs. Maintaining the integrity of the refractory lining for the molten slag has been the main problem. Steam generators with slagging-furnaces, including cyclone furnaces, are proposed only when the long-range fuel supply has characteristics closely similar to those of fuels which have demonstrated their suitability for cyclone-firing (Ref. B-34). Ironically, the slagging-furnaces at the Mercer Generating Station established several efficiency records. In 1961, for example, plant heat-rate, as reported by the Federal Power Commission, stood at 8,894 Btu/kw-hr, the lowest in the world for a drum-boiler, single-reheat installation. The following year a record of 8,874 Btu/kw-hr was set (Refs. B-35 and -36). These units are operated, however, at unusually high steam-temperatures. In recent years, the trend of the utilities has clearly indicated a preference for pulverized-coal firing with a dry bottom (Ref. B-37). One utility (Ref. B-19) "confirmed conclusions from an extensive study that led to rejecting the wet bottom and accepting the increased capital costs of the dry bottom as an indispensible element in continuity and low operating cost."

As suggested earlier, European experience has differed in this area. Slagging furnaces have been widely used in Germany and other countries because of the lower cost of the steam generator and ash disposal. A summary of the European experience is included in the appendix of Reference B-38. In addition, extensive research has been carried out on the utilization of slag as a by-product (Ref. B-39).

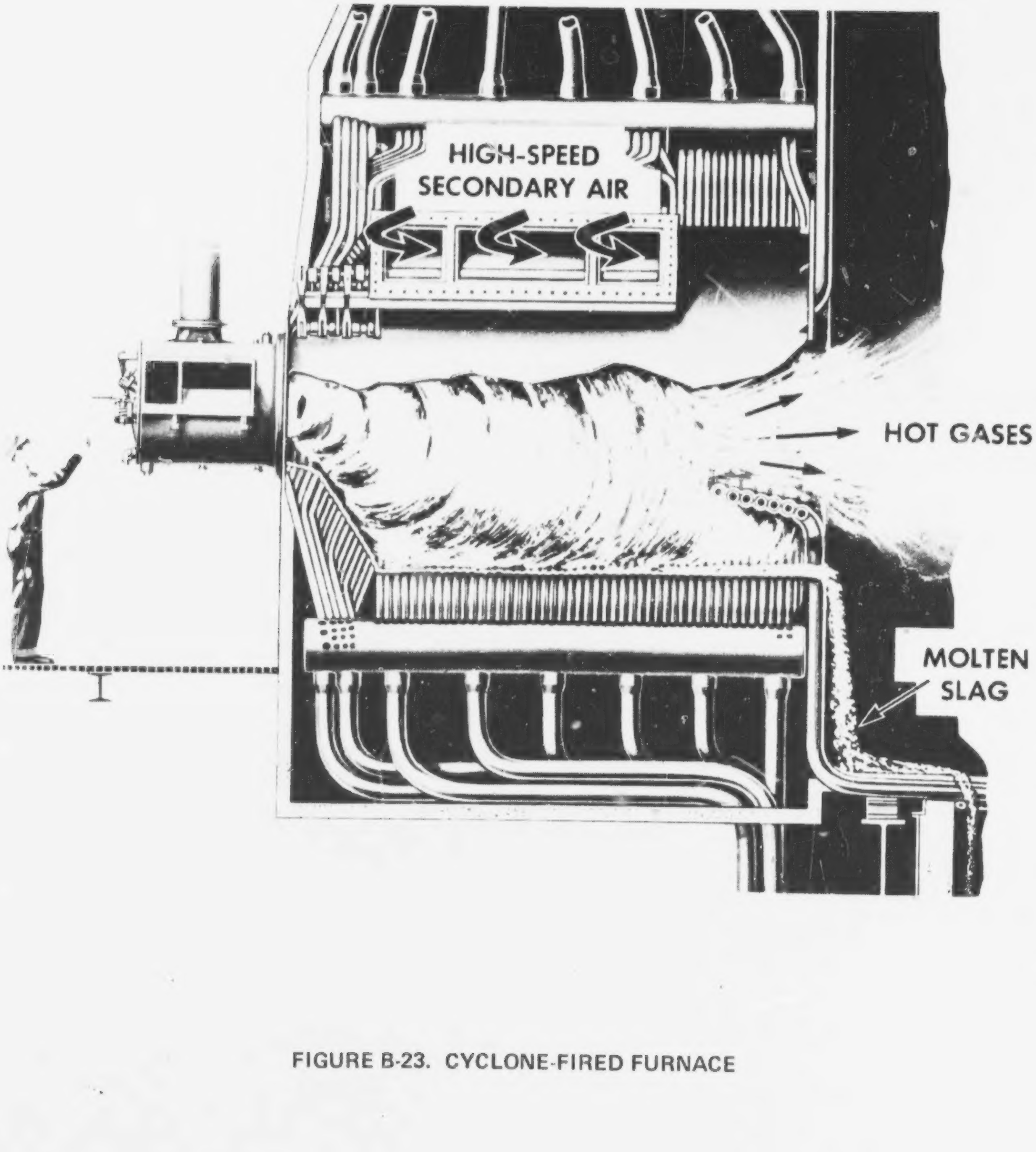

HIGH-SPEED SECONDARY AIR
HOT GASES
MOLTEN SLAG

FIGURE B-23. CYCLONE-FIRED FURNACE

3. Cost and Performance Data for Representative Designs

a. Characteristics of Ten Selected Steam Generators

A total of 10 designs was selected to exemplify the present state-of-the-art in this country in the capacity range of 44 to 400 MW. Of course, much larger units are in operation today, but units with nameplate ratings exceeding 500 MW's were considered to be outside the scope of the present survey.

The illustrative examples cover various fuels, designs, and use of steam generators. The selection includes seven natural circulation units, one controlled circulation, and two subcritical once-through units. Three of the examples are gas-, two are oil-, and five are coal-fired. Some of the units are designed to burn alternate fuels. Most of the units have horizontal burners; one has tangential, tilting burners; and one has a cyclone furnace. A summary of the performance of the 10 selected steam generators is given in Table B-1. Economic data on these units is presented in the section which follows. A brief description of each design is as follows:

Unit No. 1 - (Fig. B-24)

This is the smallest size (44 MW) unit selected for the study. It is a gas-fired steam generator having no reheat cycle. It is of the top-supported type, with two drums and a baffleless boiler bank. Six burners are located in the front wall. This type of unit is generally used for large industrial applications or for relatively small power-generation applications, such as for a municipality. Operating steam conditions may vary considerably, but usually favor the 1300 psig and 950°F level.

Unit No. 2 - (Fig. B-25)

This is a larger gas-fired, non-reheat unit of almost twice the capacity of Unit No. 1. The entire unit is supported at the bottom. It has two drums and a baffled boiler. A division waterwall is located in the furnace.

Unit No. 3 - (Fig. B-26)

This is a 100 MW central-station type steam generator. It is a coal-fired, reheat unit. The four rows of intervane burners are suitable for burning pulverized coal or oil. This generator has only one steam drum. Because of the addition of the reheater, the boiler bank found in small units is absent. In a reheat unit, a greater degree of evaporation is done in the furnace and convection area walls. This particular boiler has three stages of superheat, one of which is in the form of a radiant wall extending the entire length of the furnace. The unit has

TABLE B-1

SUMMARY PERFORMANCE OF TEN SELECTED STEAM GENERATORS

Unit No.	1	2	3	4	5	6	7	8	9	10
Unit Size, MW	44	81	100	158	200	230	245	300	327	400
Fuel	Gas	Gas	Coal	Gas	Coal	Coal	Coal	Oil	Coal	Oil
Steam Flow, 103 lb/hr	500	756	804	1,065	1,475	1,502	1,734	1,950	2,300	2,390
Pressure Superheater Outlet, psig	1,300	1,275	1,980	1,875	2,450	2,591	2,486	2,100	2,620	2,460
Temperature Superheater Outlet, ^{o}F	950	950	1,005	1,010	1,050	1,005	1,000	1,005	1,005	1,005
Temperature Reheater Outlet, ^{o}F	--	--	1,005	1,010	1,000	1,005	1,000	1,005	1,005	1,005
Temperature Gas Leaving Furnace, ^{o}F	2,100	2,355	1,870	1,810	2,330	1,880	1,850	2,365	--	1,990
Temperature Gas Leaving Air Heater, ^{o}F	274	245	307	253	257	274	285	268	--	282
Draft Loss Total, In. H_2O	--	--	--	--	--	--	--	11.90	--	--
Air Loss Total, In. H_2O	18.49	19.65	21.73	16.65	27.45	21.15	--	12.00	--	27.56
Heat Liberation Rate, Btu/hr-ft^3	22,300	39,600	16,000	27,700	21,000	16,050	15,900	24,000	--	20,800
Boiler Efficiency, %	84.23	85.44	88.26	85.23	89.27	88.94	89.32	88.92	--	88.56

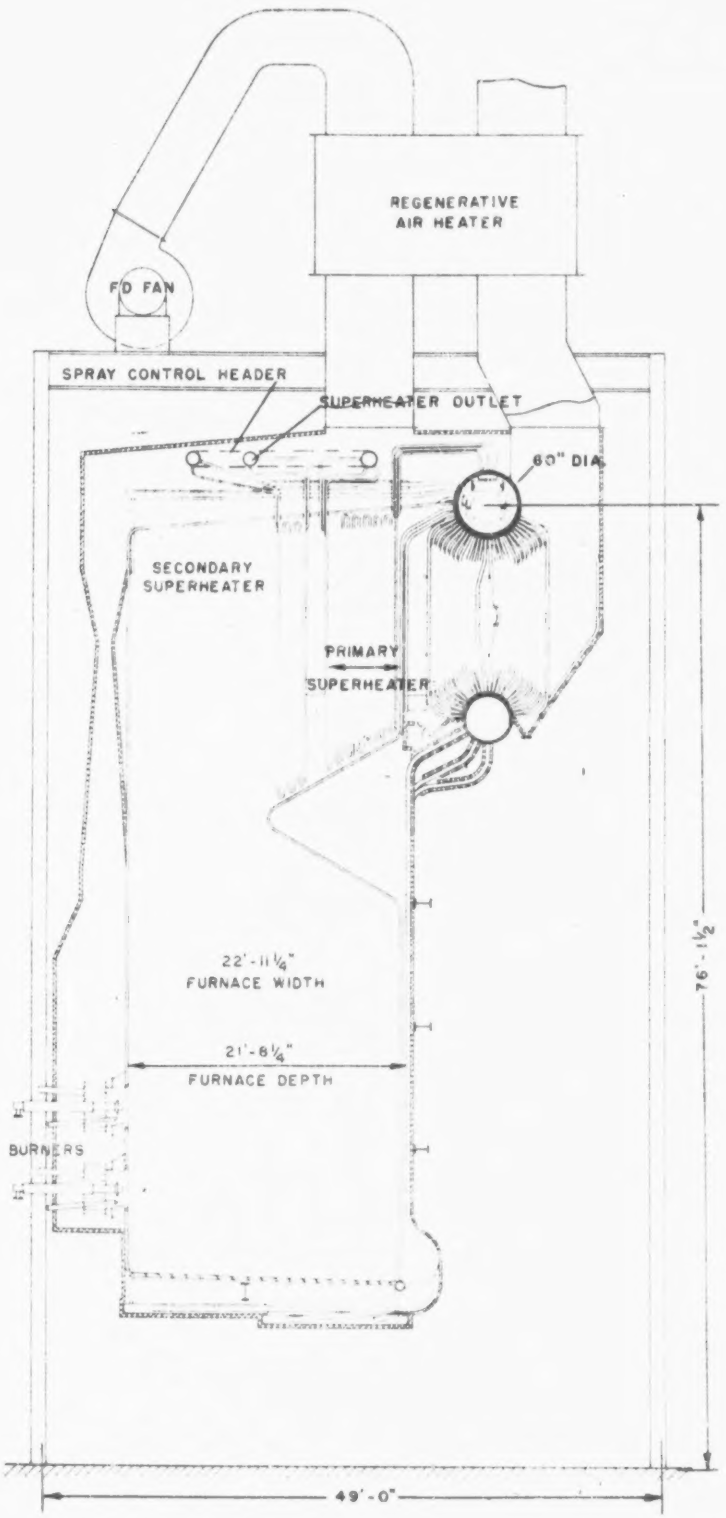

REGENERATIVE AIR HEATER
FD FAN
SPRAY CONTROL HEADER
SUPERHEATER OUTLET
60" DIA.
SECONDARY SUPERHEATER
PRIMARY SUPERHEATER
22'-11¼" FURNACE WIDTH
21'-8¼" FURNACE DEPTH
BURNERS
76'-1½"
49'-0"

FIGURE B-24. SELECTED STEAM GENERATOR DESIGNS - UNIT NO. 1

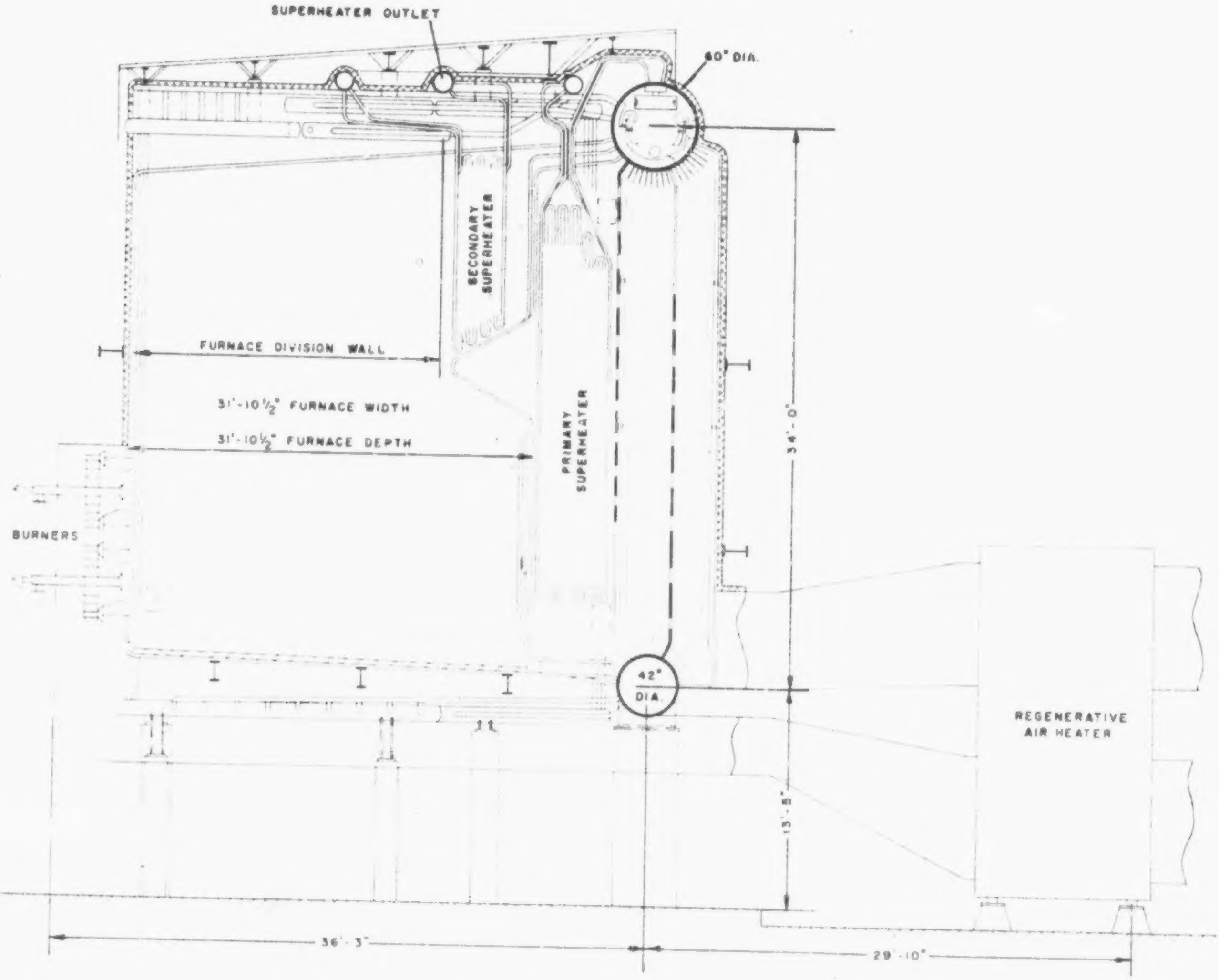

SUPERHEATER OUTLET
60" DIA.
SECONDARY SUPERHEATER
FURNACE DIVISION WALL
31'-10½" FURNACE WIDTH
31'-10½" FURNACE DEPTH
PRIMARY SUPERHEATER
34'-0"
BURNERS
42" DIA.
REGENERATIVE AIR HEATER
13'-8"
36'-3"
29'-10"

FIGURE B-25. SELECTED STEAM GENERATOR DESIGNS - UNIT NO. 2

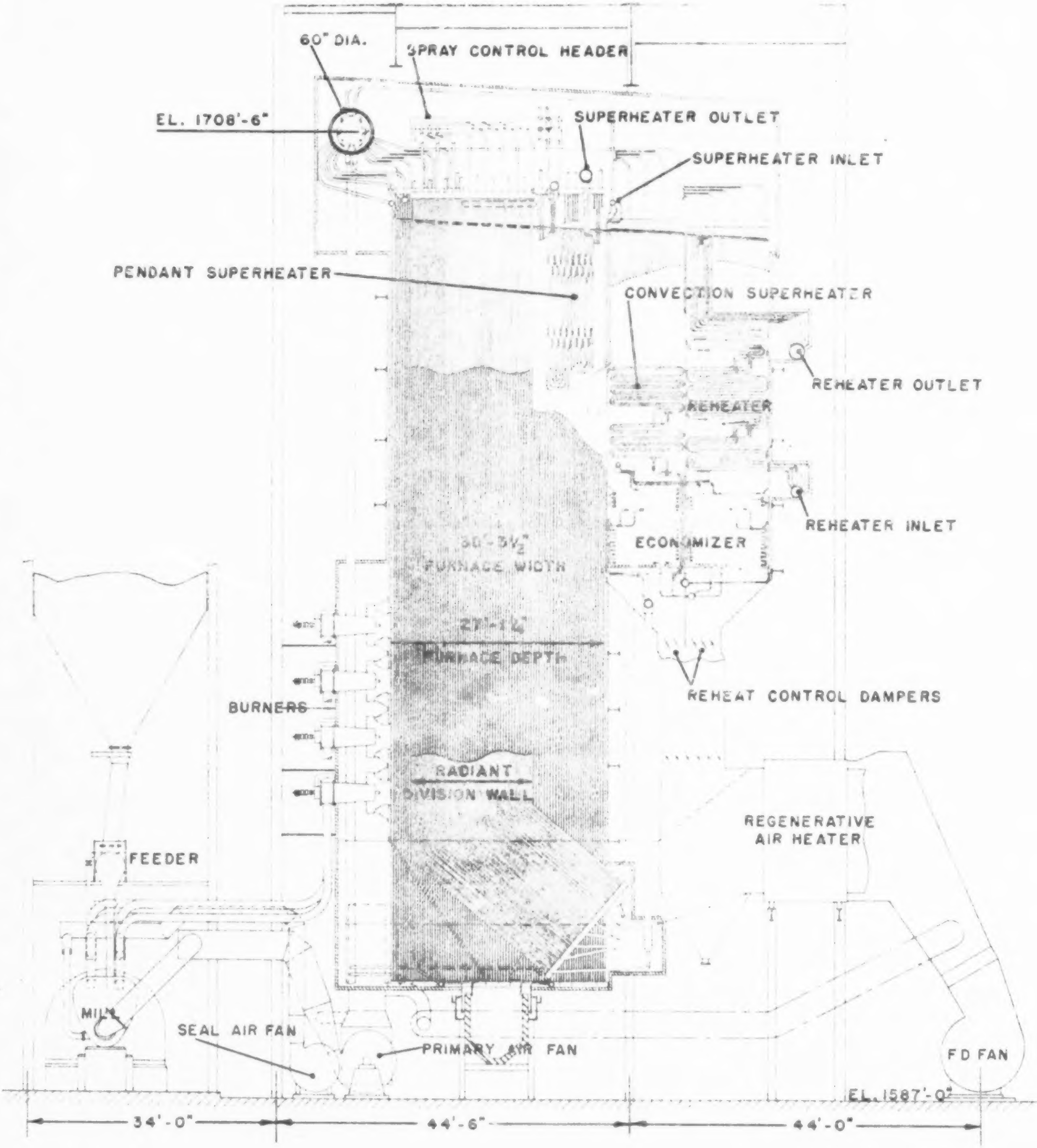

60" DIA.
SPRAY CONTROL HEADER
EL. 1708'-6"
SUPERHEATER OUTLET
SUPERHEATER INLET
PENDANT SUPERHEATER
CONVECTION SUPERHEATER
REHEATER OUTLET
REHEATER
REHEATER INLET
30'-3½"
FURNACE WIDTH
ECONOMIZER
27'-1¼"
FURNACE DEPTH
REHEAT CONTROL DAMPERS
BURNERS
RADIANT
DIVISION WALL
REGENERATIVE
AIR HEATER
FEEDER
MILL
SEAL AIR FAN
PRIMARY AIR FAN
FD FAN
EL. 1587'-0"
34'-0"
44'-6"
44'-0"

FIGURE B-26. SELECTED STEAM GENERATOR DESIGNS - UNIT NO. 3

a parallel pass arrangement of superheater and reheater convection surfaces to facilitate steam temperature control. Heat recovery by economizer and air heater follows the parallel pass.

Unit No. 4 (Fig. B-27)

This is a 158 MW utility unit designed for gas firing. In this unit, the radiant superheater-stage is composed of several tube panels suspended in the upper portion of the furnace.

Unit No. 5 (Fig. B-28)

This is a 200 MW coal-fired utility generator. It is of the once-through, subcritical, design. This type of unit has no drum and differs from the natural circulation (drum) unit mainly in the circuitry of the furnace walls. The coal pulverizing mills are of the medium-speed, planetary roll and table type, which pulverizes fuels to any desired, uniform fineness. The pulverized fuel is fired in burners arranged for opposed firing.

Unit No. 6 (Fig. B-29)

This illustration shows a 230 MW, natural circulation, coal-fired unit. The coal-burners are located in the front walls. Again, mills are used to pulverize the bituminous coal.

Unit No. 7 (Fig. B-30)

This 245 MW unit is of the controlled circulation, twin-furnace design. It is similar to the one-drum, natural-circulation generator, except it has a pump to force the circulation of the water in the generator. The mills pulverize the coal, which is then exhausted to the burners. These are of the tangential type and are located at the four corners of the furnace. These burners can be tilted up or down and are useful in controlling the steam temperature over a wide range of loads.

Unit No. 8 (Fig. B-31)

This is a 300 MW unit specifically designed for oil firing. It has a reheater-bypass for the control of steam temperature. There are two radiant division-walls in the furnace and a radiant superheater-section located in a portion of the front furnace-wall.

Unit No. 9 (Fig. B-32)

This illustration shows a 327 MW coal-fired unit. In this installation, crushed coal is introduced at the burner end of several cyclone furnaces located near the bottom of the main furnace. This cyclone-firing is a method of burning low-fusion, high ash-content bituminous coals. The superheater and reheater sections in this unit are arranged in series. Steam temperature control is frequently obtained by recirculating gas from the economizer pass to the furnace.

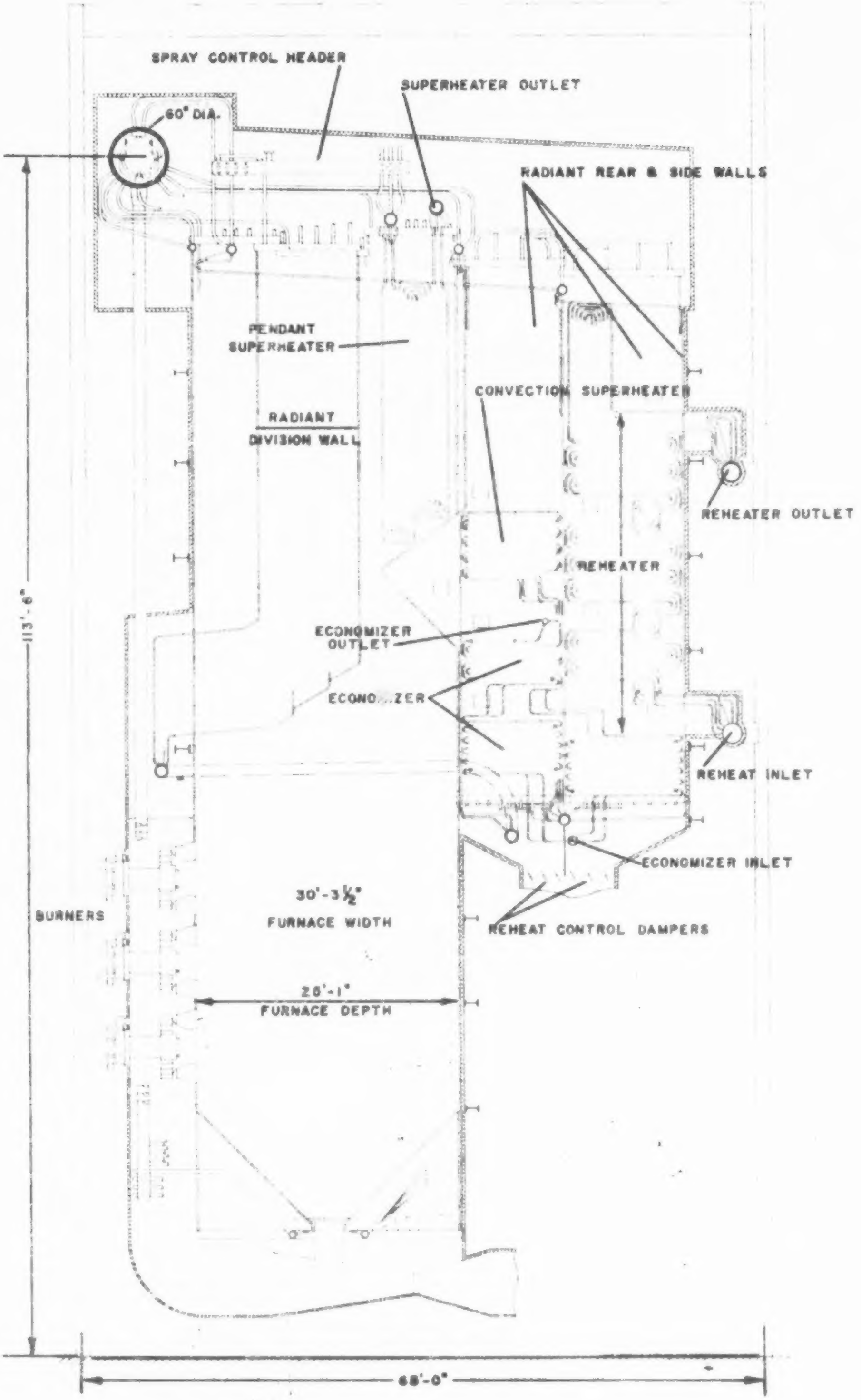

SPRAY CONTROL HEADER
SUPERHEATER OUTLET
60" DIA.
RADIANT REAR & SIDE WALLS
PENDANT SUPERHEATER
CONVECTION SUPERHEATER
RADIANT DIVISION WALL
REHEATER OUTLET
REHEATER
ECONOMIZER OUTLET
ECONOMIZER
REHEAT INLET
ECONOMIZER INLET
113'-6"
BURNERS
30'-3½"
FURNACE WIDTH
REHEAT CONTROL DAMPERS
25'-1"
FURNACE DEPTH
68'-0"

FIGURE B-27. SELECTED STEAM GENERATOR DESIGNS - UNIT NO. 4

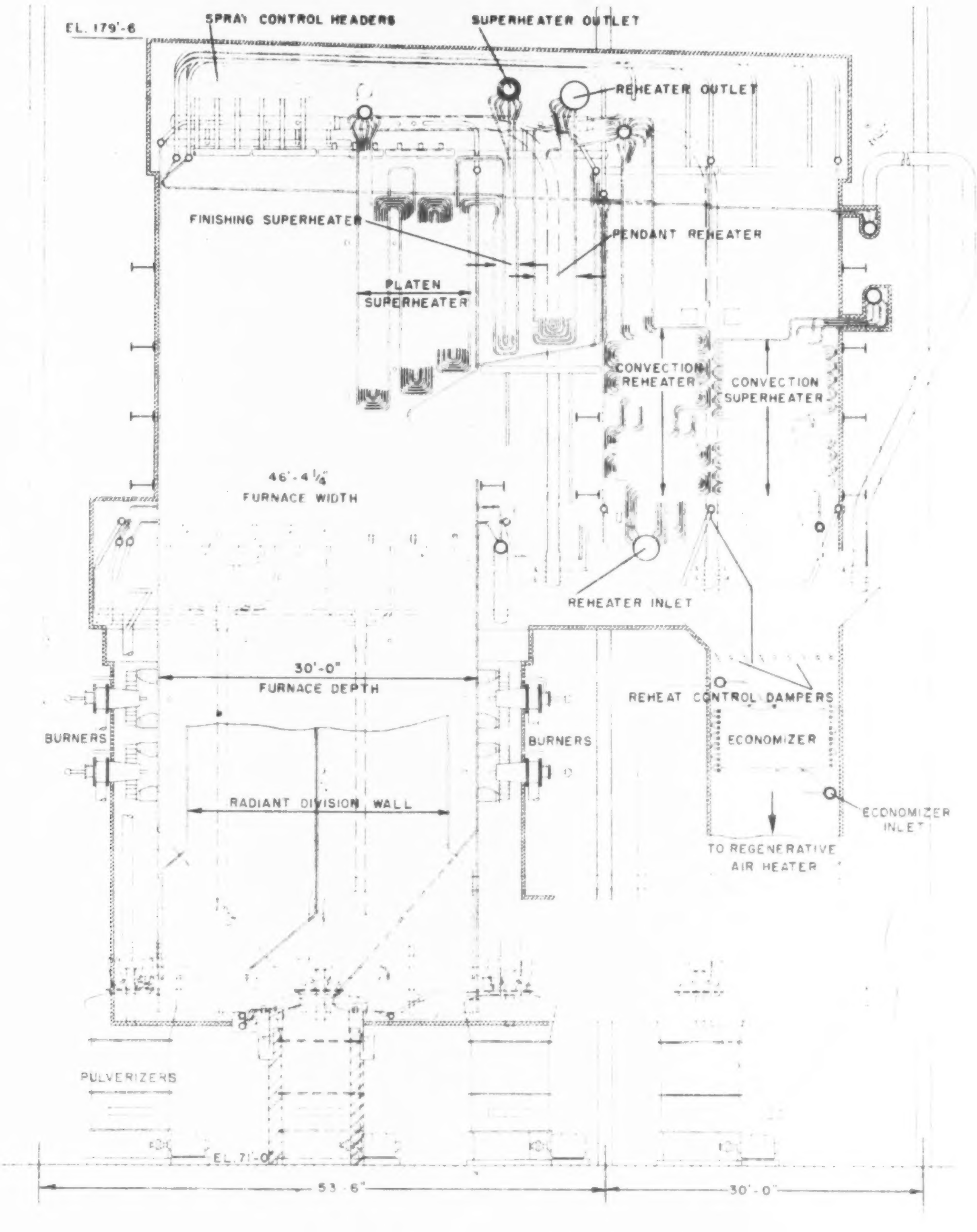

EL. 179'-6
SPRAY CONTROL HEADERS
SUPERHEATER OUTLET
REHEATER OUTLET
FINISHING SUPERHEATER
PENDANT REHEATER
PLATEN SUPERHEATER
CONVECTION REHEATER
CONVECTION SUPERHEATER
46'-4 1/4" FURNACE WIDTH
REHEATER INLET
30'-0" FURNACE DEPTH
REHEAT CONTROL DAMPERS
BURNERS
BURNERS
ECONOMIZER
RADIANT DIVISION WALL
ECONOMIZER INLET
TO REGENERATIVE AIR HEATER
PULVERIZERS
EL. 71'-0"
53'-6"
30'-0"

FIGURE B-28. SELECTED STEAM GENERATOR DESIGNS - UNIT NO. 5

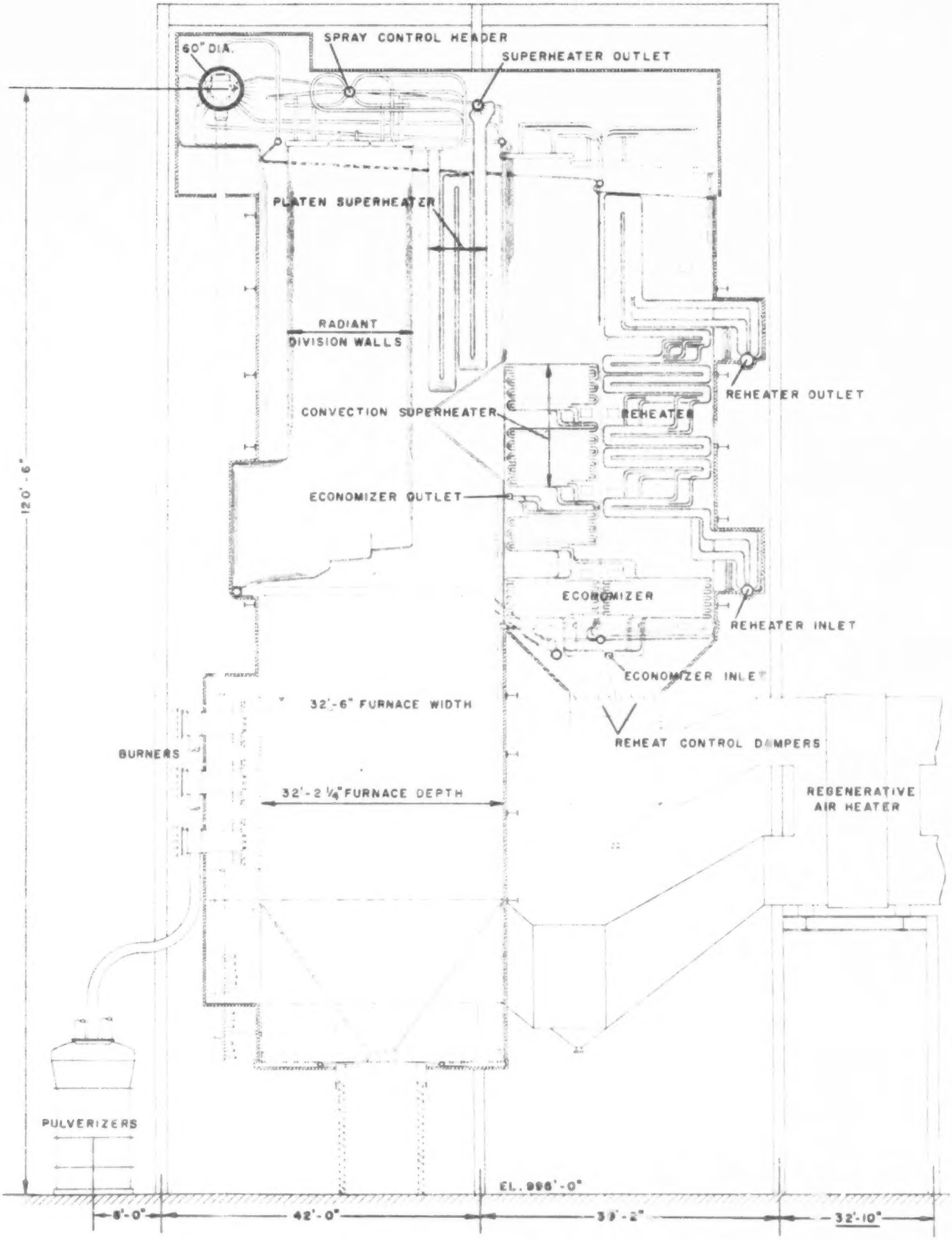

60" DIA.
SPRAY CONTROL HEADER
SUPERHEATER OUTLET
PLATEN SUPERHEATER
RADIANT DIVISION WALLS
CONVECTION SUPERHEATER
REHEATER
REHEATER OUTLET
ECONOMIZER OUTLET
ECONOMIZER
REHEATER INLET
ECONOMIZER INLET
32'-6" FURNACE WIDTH
REHEAT CONTROL DAMPERS
BURNERS
32'-2 1/4" FURNACE DEPTH
REGENERATIVE AIR HEATER
120'-6"
PULVERIZERS
EL. 996'-0"
8'-0"
42'-0"
37'-2"
32'-10"

FIGURE B-29. SELECTED STEAM GENERATOR DESIGNS - UNIT NO. 6

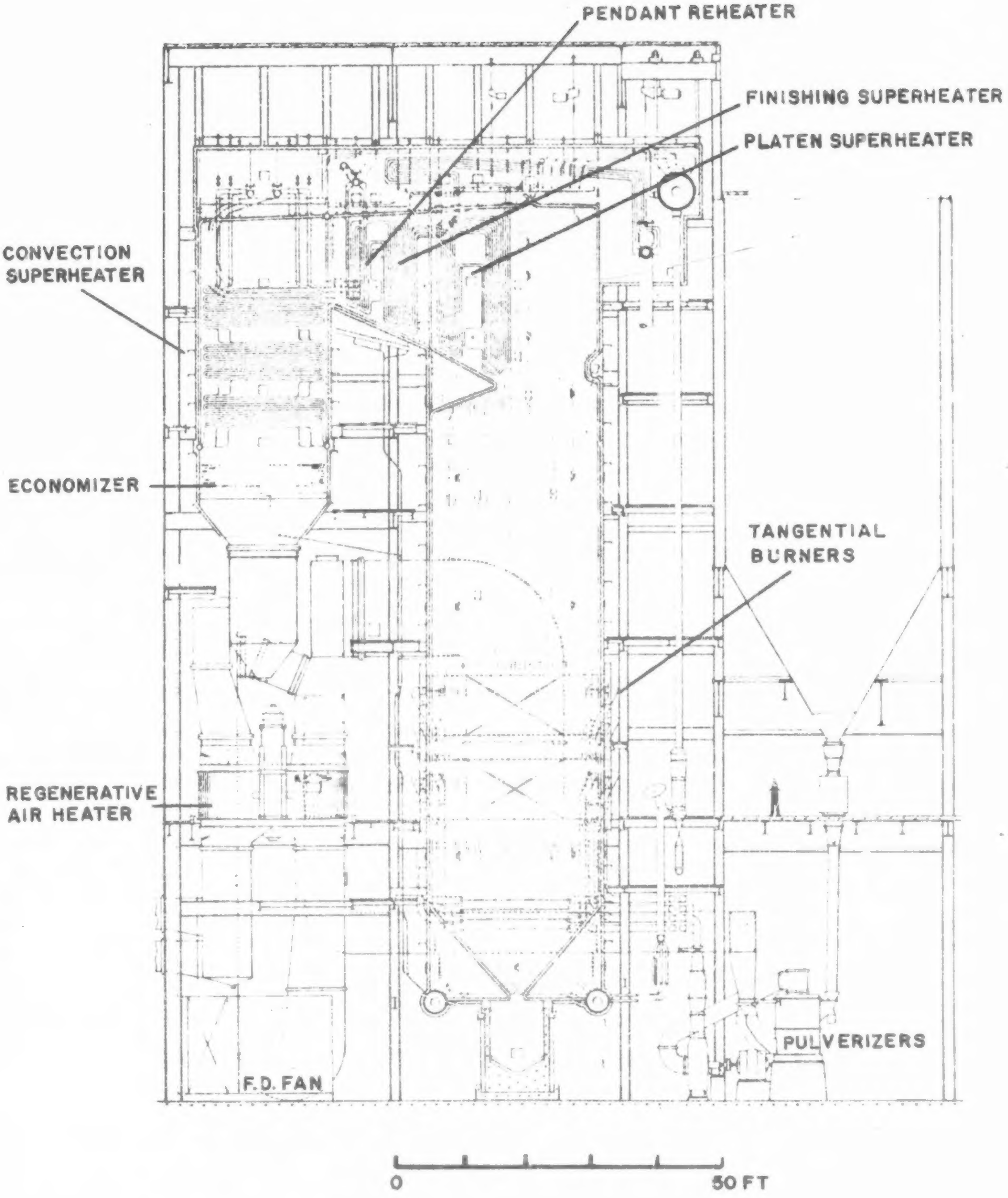

PENDANT REHEATER
FINISHING SUPERHEATER
PLATEN SUPERHEATER
CONVECTION SUPERHEATER
ECONOMIZER
TANGENTIAL BURNERS
REGENERATIVE AIR HEATER
PULVERIZERS
F.D. FAN
0
50 FT

FIGURE B-30. SELECTED STEAM GENERATOR DESIGNS - UNIT NO. 7

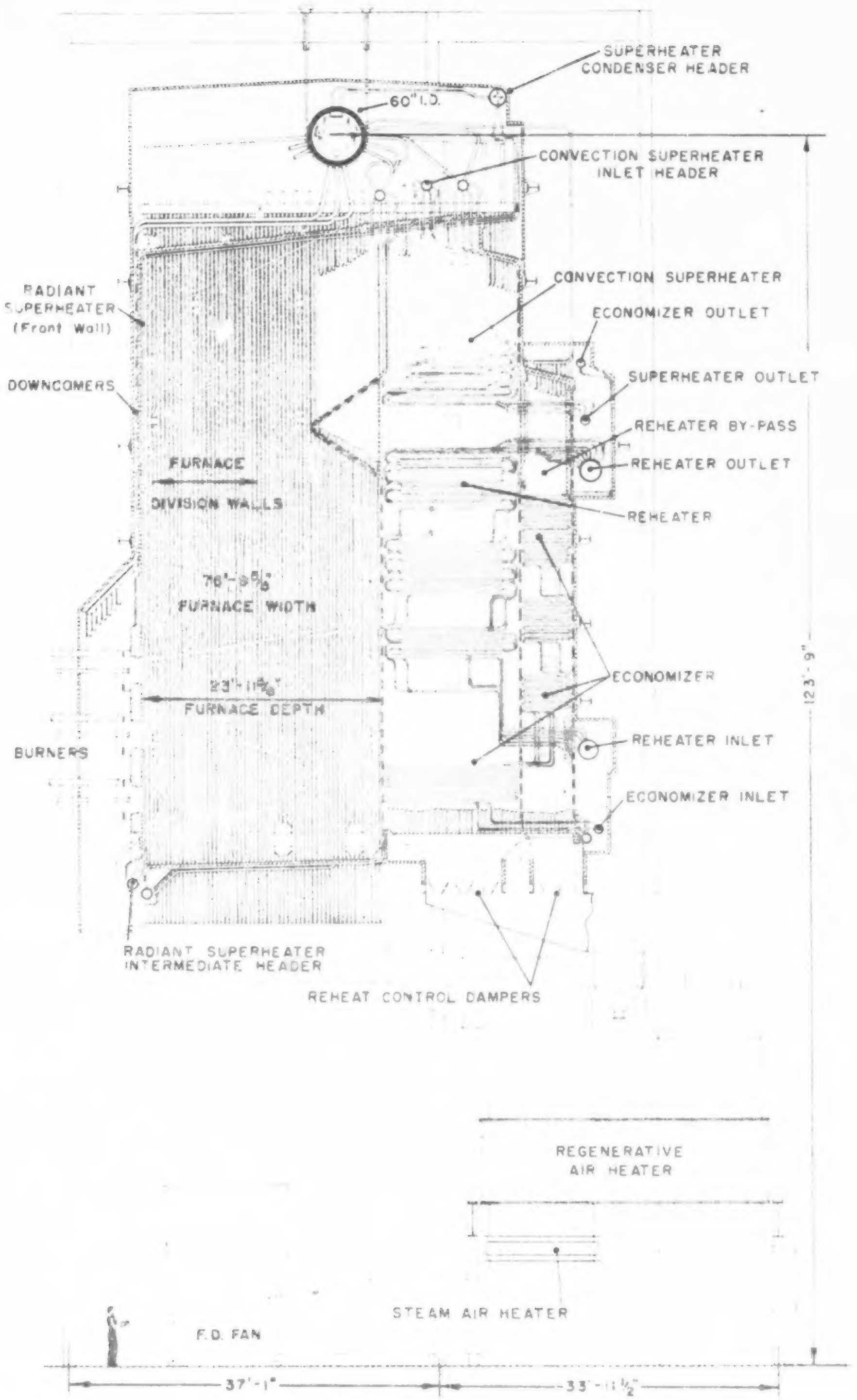

SUPERHEATER CONDENSER HEADER
60" I.D.
CONVECTION SUPERHEATER INLET HEADER
RADIANT SUPERHEATER (Front Wall)
CONVECTION SUPERHEATER
ECONOMIZER OUTLET
DOWNCOMERS
SUPERHEATER OUTLET
REHEATER BY-PASS
REHEATER OUTLET
FURNACE DIVISION WALLS
REHEATER
76'-8 5/8"
FURNACE WIDTH
ECONOMIZER
23'-11 5/8"
FURNACE DEPTH
123'-9"
REHEATER INLET
BURNERS
ECONOMIZER INLET
RADIANT SUPERHEATER INTERMEDIATE HEADER
REHEAT CONTROL DAMPERS
REGENERATIVE AIR HEATER
STEAM AIR HEATER
F.D. FAN
37'-1"
33'-11 1/2"

FIGURE B-31. SELECTED STEAM GENERATOR DESIGNS - UNIT NO. 8

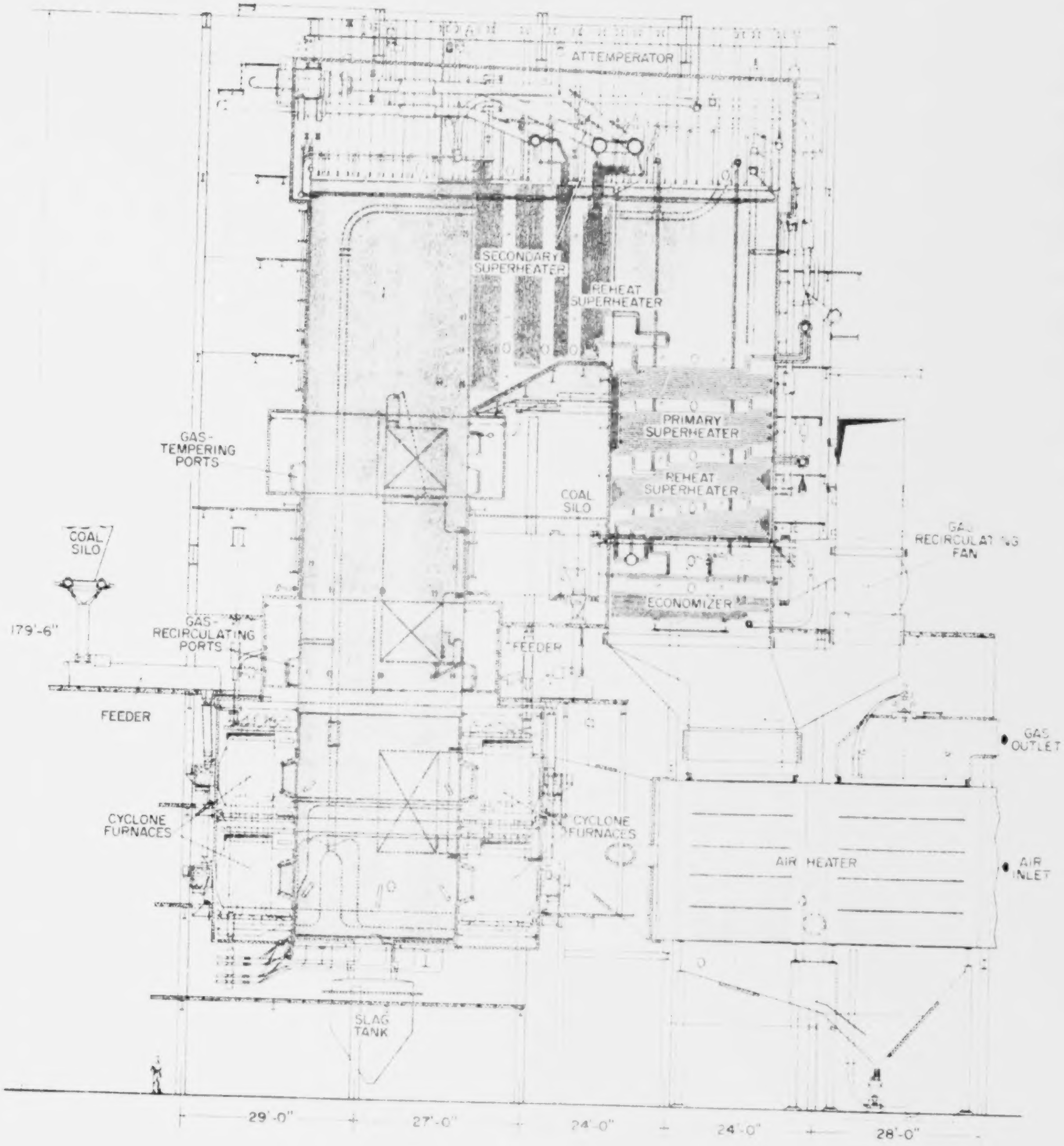

ATTEMPERATOR
SECONDARY SUPERHEATER
REHEAT SUPERHEATER
PRIMARY SUPERHEATER
REHEAT SUPERHEATER
COAL SILO
GAS-TEMPERING PORTS
COAL SILO
179'-6"
GAS-RECIRCULATING PORTS
FEEDER
FEEDER
GAS RECIRCULATING FAN
ECONOMIZER
GAS OUTLET
CYCLONE FURNACES
CYCLONE FURNACES
AIR HEATER
AIR INLET
SLAG TANK
29'-0"
27'-0"
24'-0"
24'-0"
28'-0"

FIGURE B-32. SELECTED STEAM GENERATOR DESIGNS - UNIT NO. 9

Unit No. 10 (Fig. B-33)

This is the largest unit (400 MW) used for this survey. It is a natural-circulation, oil-fired, steam generator. The superheater has a front-wall radiant section in addition to a platen section at the furnace outlet, a pendant spaced-tube section behind the platen, and a horizontal convection-section in parallel with the reheater in the rear pass.

b. Economic Analysis

(1) Cost Data* Based on Ten Selected Designs

A convenient method of presenting capital costs of these plants is by using the Federal Power Commission Uniform System of Accounting. Major items in this system consist of the following:

F.P.C. Code Number	Description
310	Land
311	Structures
312	Boiler Plant Equipment
314	Turbine Generator Equipment
315	Accessory Electrical Equipment
316	Miscellaneous Plant Equipment
-	Other Expenses

The sources used in determining the capital costs for the 10 units selected for this study are References B-17 and B-40 to -42.

To develop Table B-2, a correlation was first obtained between unit capacity and the various component costs. This was done in the form of graphs and tabulations. Figures B-34 and B-35 show these relationships for the boiler plant and the turbine generator plant. Such costs as land and structures vary considerably for units of the same size. This is understandable as land value and the type of structures needed vary with the location.

The Boiler Plant Equipment costs (Code 312) were further subdivided as shown in Table B-2. The main source of information for the breakdown is the data of George (Ref. B-42). For example, the feed-water equipment (Code 122) in George's study, cost $1,300,000 for the average unit he considered. This amount represents 7.9% of the total cost of the boiler plant equipment. In a corresponding gas fired unit,

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*Unless otherwise specified, the base date for all cost data in this report is July 1969.

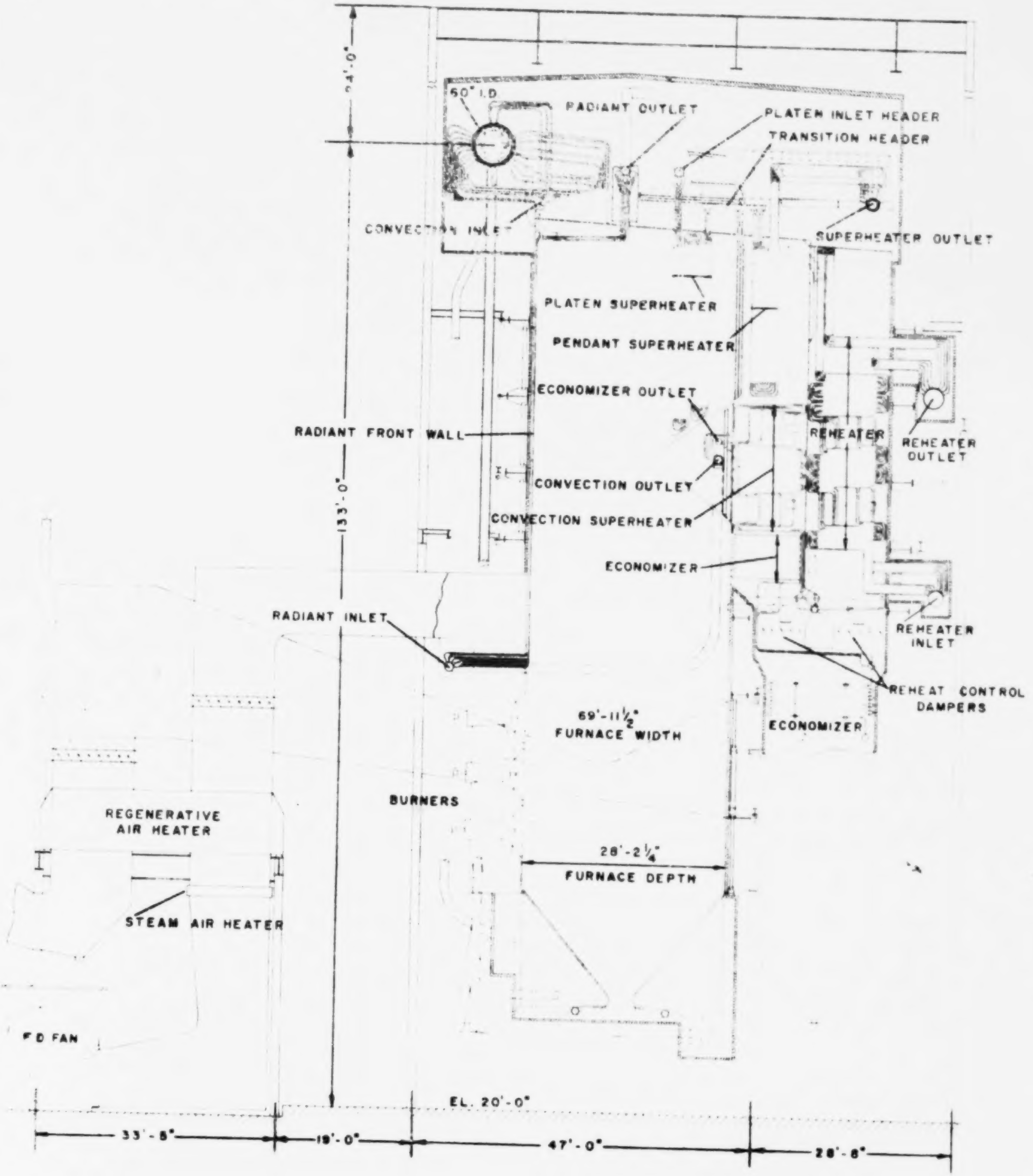
24'-0"
60" I.D.
RADIANT OUTLET
PLATEN INLET HEADER
TRANSITION HEADER
CONVECTION INLET
SUPERHEATER OUTLET
PLATEN SUPERHEATER
PENDANT SUPERHEATER
ECONOMIZER OUTLET
RADIANT FRONT WALL
REHEATER
REHEATER OUTLET
CONVECTION OUTLET
CONVECTION SUPERHEATER
133'-0"
ECONOMIZER
RADIANT INLET
REHEATER INLET
REHEAT CONTROL DAMPERS
69'-11½"
FURNACE WIDTH
ECONOMIZER
BURNERS
REGENERATIVE AIR HEATER
28'-2¼"
FURNACE DEPTH
STEAM AIR HEATER
F D FAN
EL. 20'-0"
33'-8"
19'-0"
47'-0"
28'-8"

FIGURE B-33. SELECTED STEAM GENERATOR DESIGNS - UNIT NO. 10

TABLE B-2

CAPITAL COSTS OF TEN SELECTED STEAM GENERATORS

Values In $1000 other than bottom line

Unit No.	1	2	3	4	5	6	7	8	9	10
Unit Size, MW	44	81	100	158	200	230	245	300	327	400
Fuel	Gas	Gas	Coal	Gas	Coal	Coal	Coal	Oil	Coal	Oil
310-Land & Land Rights	100	130	150	210	240	260	260	280	290	300
311-Structures & Improvements	850	1,070	2,650	1,990	5,460	6,290	6,690	3,170	9,010	4,350
312-Boiler Plant Equipment										
120-Boiler & Accessories	1,147	1,600	3,430	3,320	5,820	6,300	6,540	6,030	7,600	7,180
121-Draft Equipment	480	670	1,185	1,385	2,010	2,180	2,260	2,360	2,620	2,800
122-Feedwater Equipment	372	525	682	1,072	1,160	1,255	1,300	1,480	1,515	1,755
123-Fuel Handling & Storage	--	--	1,010	-	1,720	1,860	1,925	135	2,240	159
124-Fuel Burning Equipment	81	115	760	238	1,295	1,400	1,450	413	1,685	479
125-Ash Handling Equipment	--	--	233	--	397	425	445	60	515	79
126-Water Supply & Treating	108	150	199	310	338	365	369	445	440	527
128-Boiler Instr & Controls	112	158	251	326	420	460	461	535	555	611
129-Boiler Plant Piping	450	632	900	1,305	1,540	1,655	1,700	1,990	1,990	2,360
Total Boiler Plant Equip	2,750	3,850	8,650	7,950	14,700	15,900	16,450	13,450	19,150	15,950
314-Turbine Generator Equip	2,650	3,650	5,600	7,650	8,950	9,550	9,850	10,750	11,150	12,400
315-Accessory Elec Equip	810	1,030	1,450	1,450	1,950	2,120	2,210	1,650	2,650	1,950
316-Misc Plant Equip	90	100	160	110	260	330	370	320	580	540
Other Expenses	1,690	2,030	2,460	3,820	4,720	5,310	5,650	6,600	7,120	7,980
Total Plant Cost	8,940	11,860	21,120	23,180	36,280	39,760	41,480	36,220	49,950	43,470
Unit Capacity Cost ($/KW)	203	147	211	147	182	173	168	121	153	108

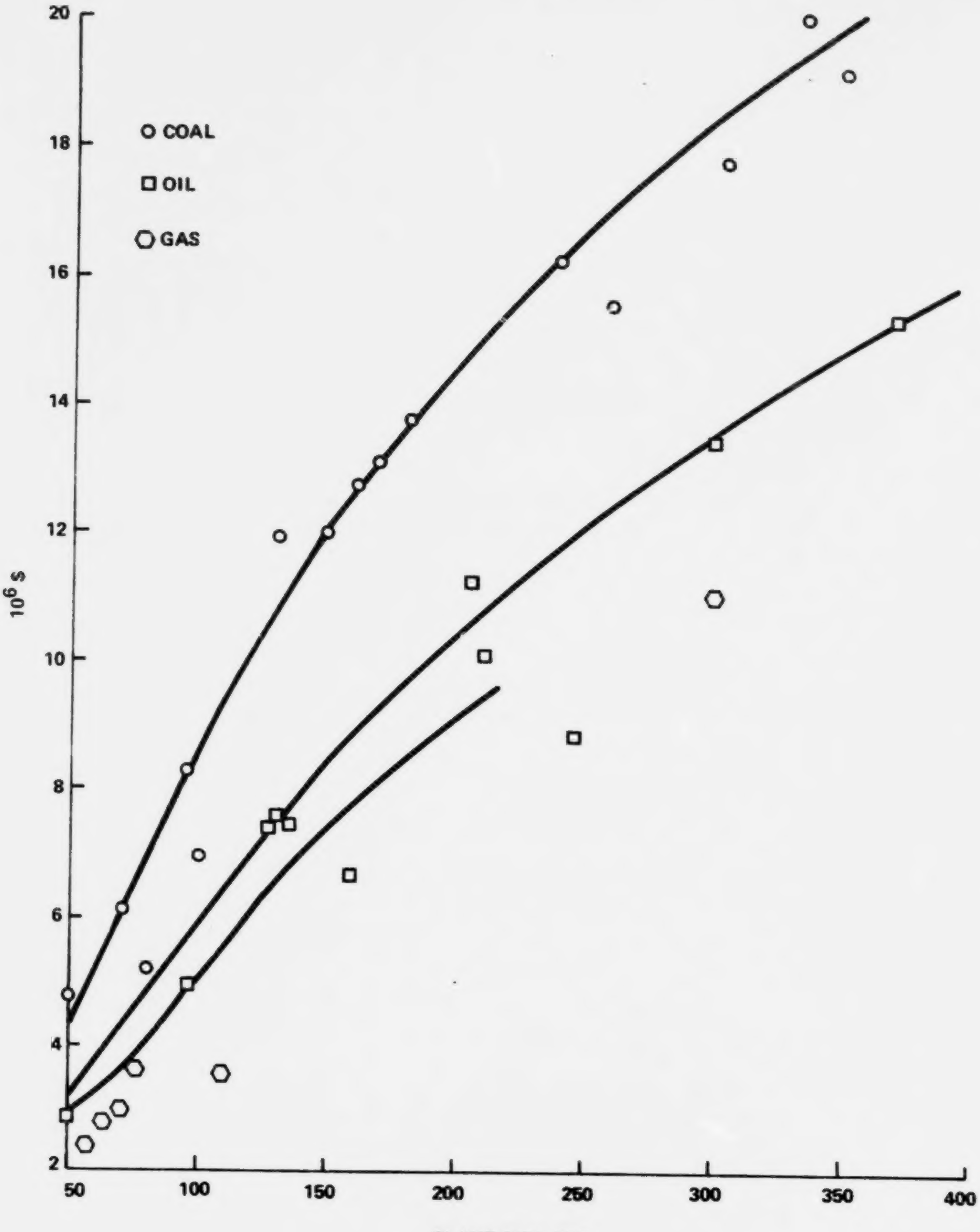

FIGURE B-34. BOILER PLANT EQUIPMENT COST

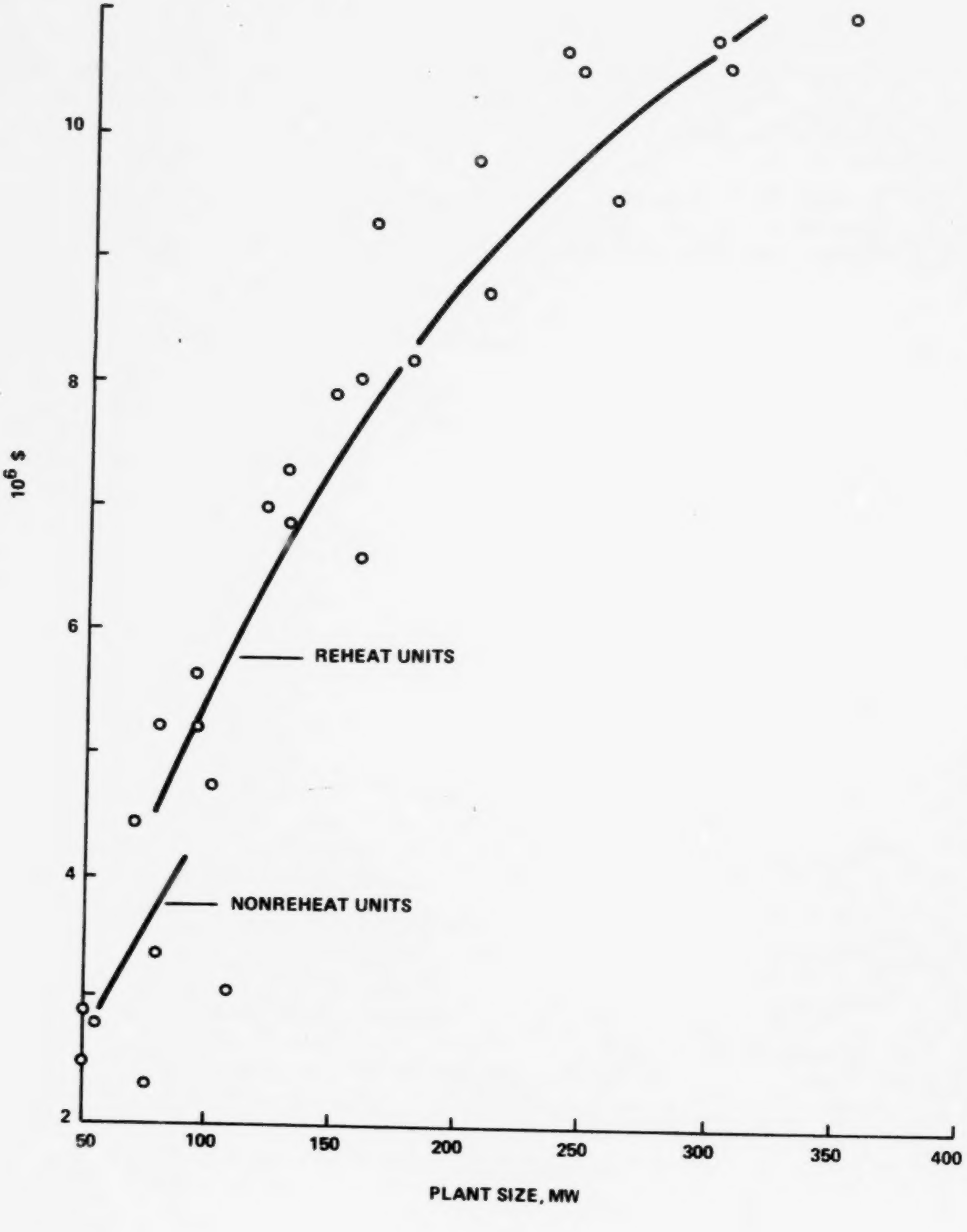

FIGURE B-35. TURBINE GENERATOR EQUIPMENT COST the feedwater equipment was assumed to cost the same amount, but with relation to the cost of gas-fired boiler plant equipment this represents 13.5% of the total.

An item, "other expenses," is also included in Table B-2. This item covers miscellaneous costs such as transmission plant structures and equipment, indirect construction expenses, design engineering, administrative expense, and other general expenses.

Energy costs are another important factor to be considered in evaluating the economics of a steam power plant. These costs are the sum of the operating expenses and the fixed charges.

The operation costs consist of the operating and maintenance charges, and fuel charges. The operating and maintenance charges include wages, supervision, maintenance, and repairs. The fuel charges are a function of the plant heat rate, net generation, and fuel cost-rate.

For this study, the values used for the various factors making up the operation costs were derived mainly from the data contained in References B-40 and B-43. A reasonable correlation was obtained between operating expenses (exclusive of fuel) and size of unit. These expenses vary with the type of fuel fired.

In the determination of fuel charges, it was necessary to establish values for plant factor, plant heat-rate, and fuel cost-rate. The source of data was the same as for the operation expense (Refs. B-40, -41, and -43). The plant factor, which can be defined as the ratio of the average load to the rated capacity over a stated time period, was found to be higher for coal-fired units than oil units, gas-fired units having the lowest plant factor. Size of unit did not affect the plant factor. From this investigation, it was decided to use plant-factor values of 70%, 60% and 50% for coal, oil and gas units, respectively.

A plot of net heat-rates vs size of unit for different steam-cycles was made for the various units. Values for the survey were then taken directly from this graph. Similarly, the cost of fuel was investigated. Values per million Btu's of $0.25, $0.32, and $0.22 for coal, oil, and gas, respectively, were found to be representative of costs in this country as of early 1969. The fuel charges were then calculated from the capacity rating of the unit, its plant factor, heat-rate and fuel cost-rate.

Fixed charges for a steam power plant include costs of capital, depreciation, insurance, property taxes, State and Federal taxes, and other smaller items. These fixed charges vary considerably from plant to plant. A few years ago the Federal Power Commission suggested that an annualization rate of 12.4% would represent a good average. In view of the fact that interest rates have gone up considerably in recent years, a value of 15% was selected as the fixed-charges rate for this study. This rate, applied to the total plant costs shown in Table B-2, produced the fixed charges for the units selected.

Table B-3 provides a summary of the various costs making up the total energy costs for the 10 units analyzed.

(2) Cost Data Based on German Practice

Capital costs, steam generation costs, and steam requirements of single-reheat steam power plants were supplied by Siemens America, Incorporated. Figure B-36 shows the capital costs of power plants in the 150 to 600 MW range for plants designed for firing with lignite, bituminous coal, and natural gas or oil. These costs are based on waste-heat being dissipated by cooling towers and with make-up water being obtained from a nearby river. Figures B-37 through B-39 give the total generation costs for different full-load hours per year for 100 MW, 300 MW, and 600 MW units and for three different fuel-types. The fuel costs used in developing Figures B-37 through B-39 are for December 1969 and are low rather than typical values. The conversion employed was based on a rate of exchange of 27.3 cents per German Mark (DM). The method of calculation used by Kraftwerk Union AG* is based on the computational sequence shown in Table B-4.

Fuel costs are based on the lower or net heating value of the fuels, which is general practice in Europe. In the United States it is the general practice to use the higher heating value. The following conversion factors when multiplied by European fuel costs yield fuel costs in the same currency for the higher heating values.

Fuel	Average HHV (Btu/lb)	Factor
Lignite	4,000-4,700	0.70
Bituminous Coal	12,900	0.96
Oil	18,300	0.94
Natural Gas	21,400	0.90

This conversion need only be applied to heat content of fuels and not transferred heat. In other words, the factors are applicable to net plant heat-rates but not turbine heat-rates.

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*The European principal for Siemens America.

TABLE B-3

PLANT TOTAL ENERGY COSTS OF TEN SELECTED STEAM GENERATORS

Unit No.	1	2	3	4	5	6	7	8	9	10
Capacity, MW	44	81	100	158	200	230	245	300	327	400
Fuel	Gas	Gas	Coal	Gas	Coal	Coal	Coal	Oil	Coal	Oil
Plant Factor	50	50	70	50	70	70	70	60	70	60
Plant Heat Rate, Btu/**kw-hr**	12, 700	11, 800	10, 600	10, 600	9, 550	9, 470	9, 420	9, 400	9, 300	9, 280
Net Generation, 10^6 kw-hr/yr	192	355	613	691	1, 225	1, 410	1, 505	1. 575	2, 010	2, 100
Fuel Cost, $/$10^6$ Btu's	0. 22	0. 22	0. 25	0. 22	0. 25	0. 25	0. 25	0. 32	0. 25	0. 32
1) Production **Expenses**, 10^3 $										
a) Operating and Maint.	140	200	322	328	535	600	630	700	804	900
b) Fuel	539	923	1, 625	1, 610	2, 920	3, 340	3, 540	4, 730	4, 670	6, 200
2) Fixed Charges @15%, 10^3 $	1, 340	1, 780	3, 280	3, 470	5, 450	5, 950	6, 220	5, 440	7, 490	6, 520
3) Total Energy Cost, 10^3 $	2, 019	2, 903	5, 227	5, 408	8, 905	9, 890	10, 390	10, 870	12, 964	13, 620
Total Energy Cost, mills/kw-hr	10. 43	8. 18	8. 50	7. 95	7. 28	7. 00	6. 90	7. 23	6. 45	6. 48

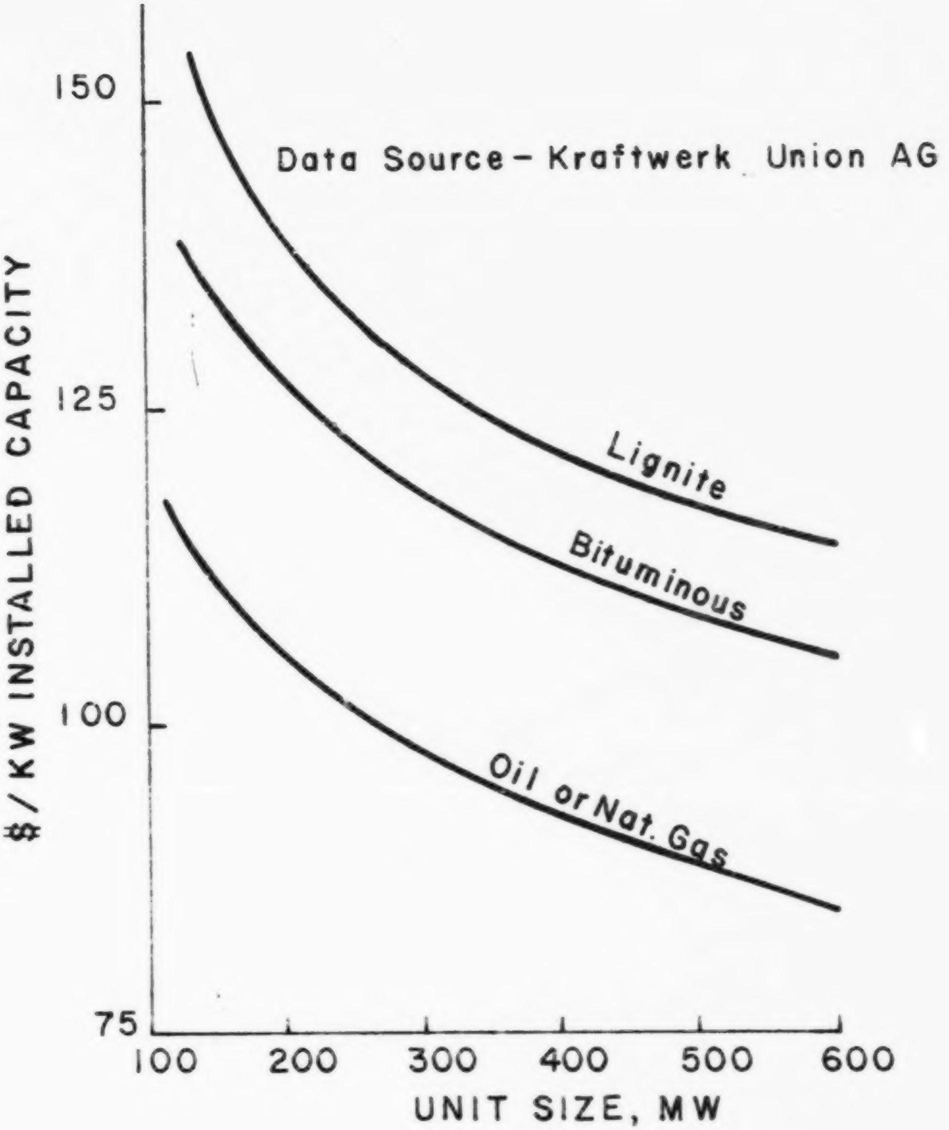


FIGURE B-36. SPECIFIC POWER PLANT CAPITAL COSTS

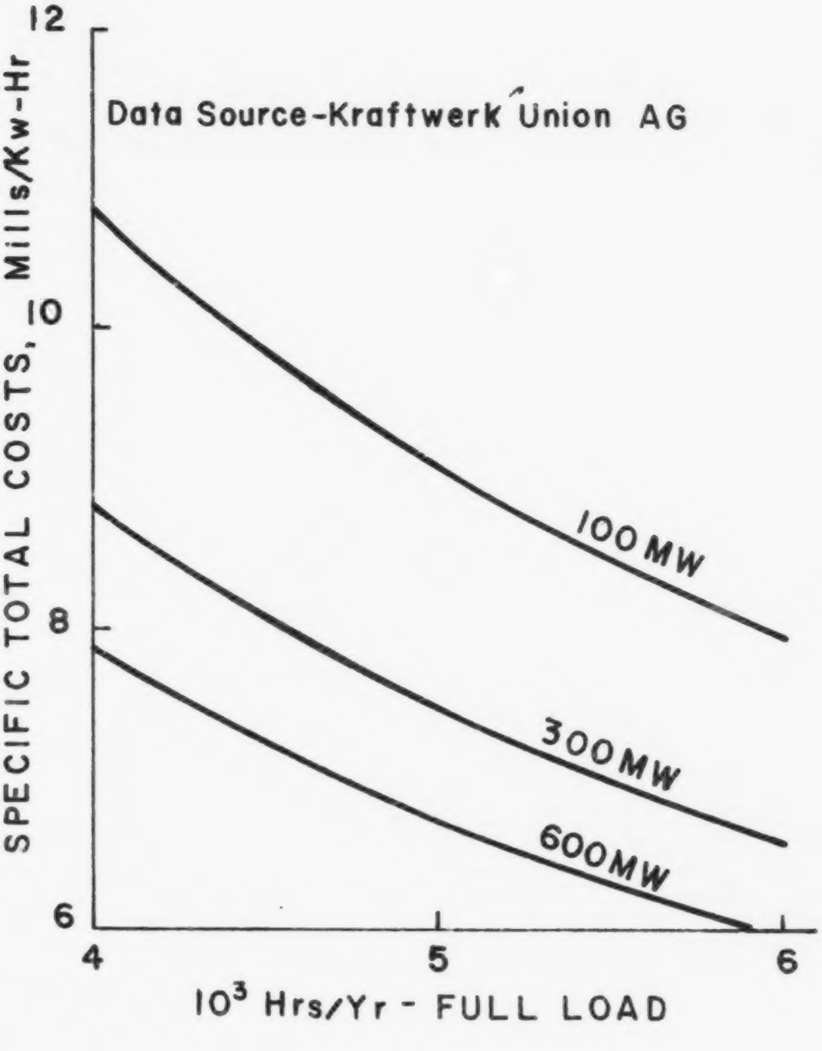


FIGURE B-37. SPECIFIC POWER PLANT TOTAL ENERGY PRODUCTION COSTS - LIGNITE

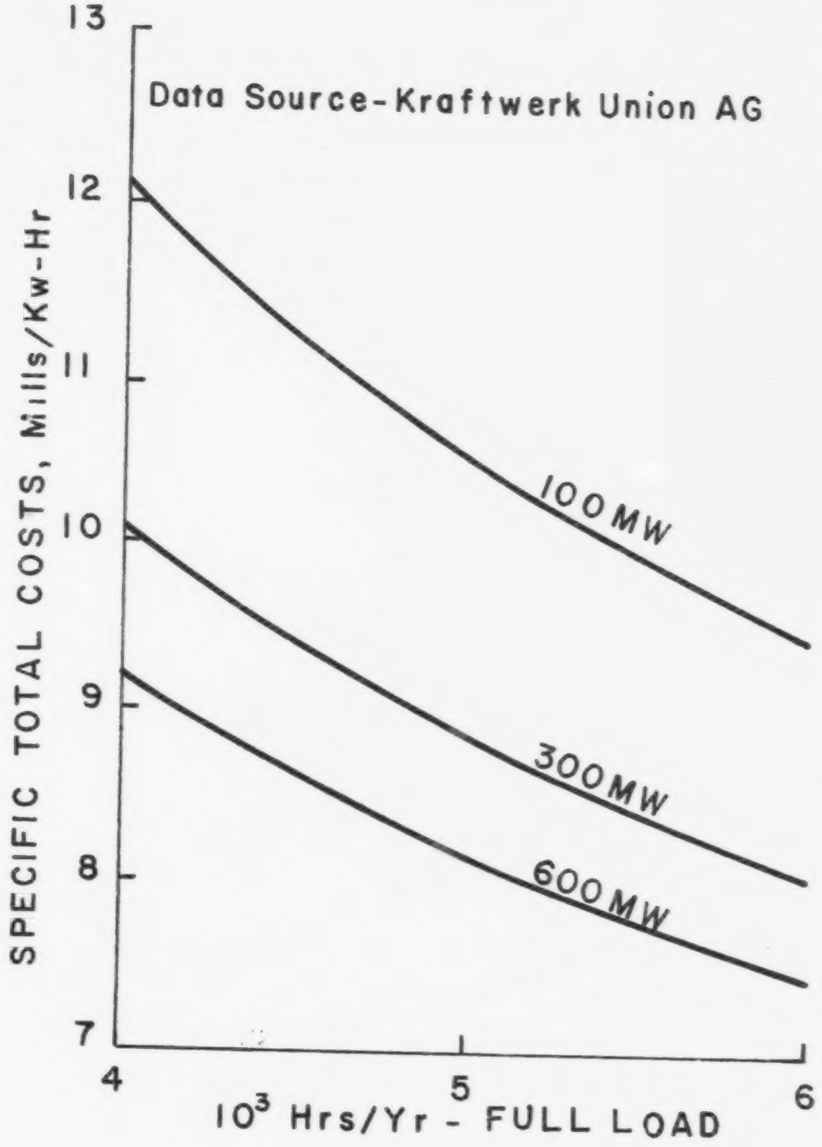


FIGURE B-38. SPECIFIC POWER PLANT TOTAL ENERGY PRODUCTION COSTS - COAL

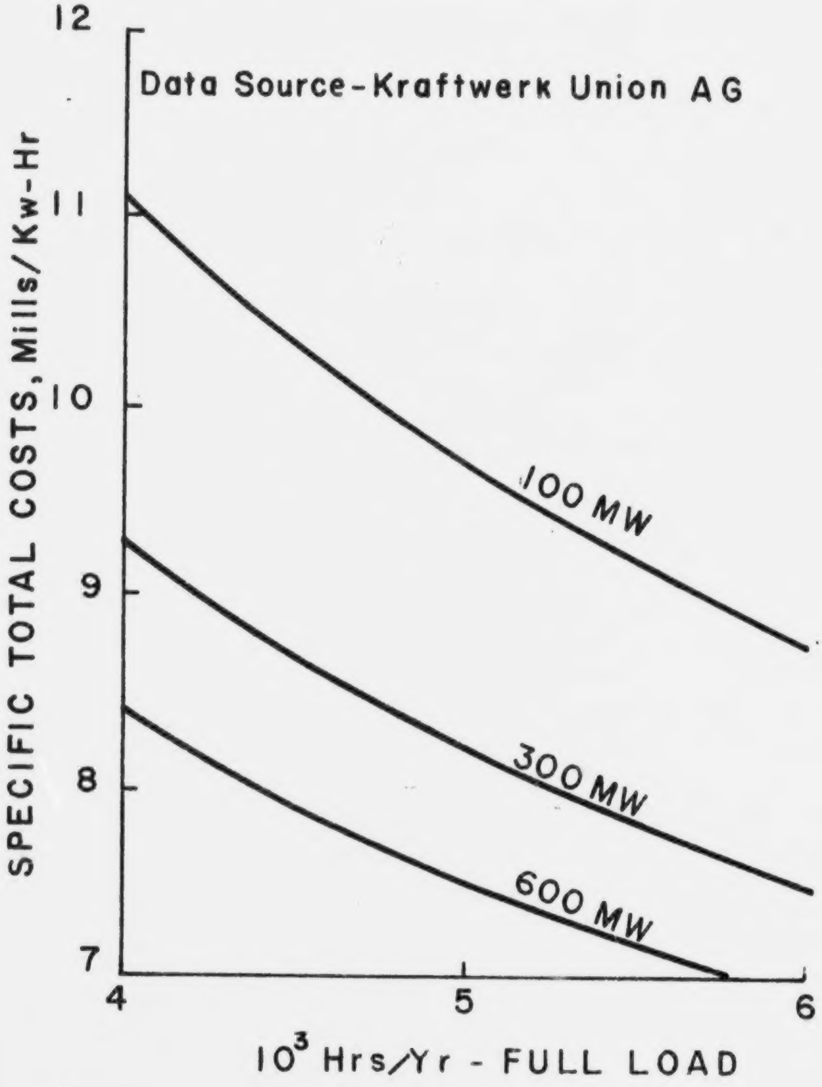


FIGURE B-39. SPECIFIC POWER PLANT TOTAL ENERGY PRODUCTION COSTS - GAS OR OIL

TABLE B-4

KRAFTWERK-UNION COMPUTATION PROCEDURE FOR DERIVING ENERGY PRODUCTION COSTS

A) Amortization Costs

		UNITS
1.	Specific power plant capital costs (derived from Figure 37)	DM/kw installed
2.	Total power plant capital costs (A1 x installed capability)	DM
3.	Interest charges during construction (8% of A2)	DM
4.	Taxes during construction (2% of A2)	DM
5.	Total capital requirements (A2 + A3 + A4)	DM
6.	Straight-line amortization (capital repayment in 17 years with 10% interest rate = 12.7% of A5)	DM per year
7.	Taxes (2% of A5)	DM per year
8.	Insurance (0.8% of A2)	DM per year
9.	Annual capital costs (A6 + A7 + A8)	DM per year
10.	Total power plant service load	kw
11.	Tranformer efficiency	%
12.	Net power plant capability (installed capability x A11 - A10 x A11)	kw
13.	Net generation with either 4,000, 5,000 or 6,000 full-load hours per year (A12 x 4,000, 5,000 or 6,000 hours, respectively)	kw-hr
14.	Specific amortization costs (A9 /A13)	Dpf/kw-hr (100 Dpf = 1 DM)

TABLE B-4 - Continued

B) Fuel Costs

1. Boiler efficiency (generally 93.5% approx.) %

2. Pipework efficiency (generally 99%) %

3. Overall plant heat consumption calculated as follows:

$$\frac{\text{Net turbine heat rate}}{B1 \times B2 \times A11 \left(1 - \frac{A10}{\text{Installed Capability}}\right)}$$ Kcal/kw-hr

4. Net plant heat consumption corrected for partial loading (by +5%, +3.5% or +2% at 4,000, 5,000 or 6,000 full-load hours per year, respectively Kcal/kw-hr

5. Specific fuel costs (fuel cost x B4) Dpf/kw-hr
Fuel cost is taken at 4DM, 5DM, 6DM and 7DM per million kilocalories for lignite, and at 7DM, 8DM, 9DM and 10DM per million kilocalories for oil, natural gas and bituminous coal.

C) Operational Costs

1. Annual compensation per man per year (generally DM 25,000) DM per year

2. Personnel requirements

for unit size of	100 MW	300 MW	600 MW
with oil or natural gas	70	80	90
with lignite or bituminous coal	90	100	110

3. Annual operational costs (C1 x C2) DM per year

4. Specific operational costs with either 4,000, 5,000 or 6,000 full-load hours p.a. (C3 A13) DM/kw-hr

D) Intermediate Summation of Specific Costs

Addition of specific costs for amortization, fuel and operation (A14 + B5 + C4). Dpf/kw-hr

E) Overhead Expenses and Lubricants (2% of D) Dpf/kw-hr

F) Specific Power Plant Total Energy Production Costs (D + E) Dpf/kw-hr

A detailed breakdown of the capital costs for 200 MW and 400 MW boilers designed for bituminous coal and for natural gas or oil is presented in Table B-5. These costs reflect typical recent-day domestic German costs, converted into U.S. currency for boiler plant equipment as defined by the Federal Power Commission under the 19 items of Electric Plant Account 312. No costs are given for Items 15 and 19 since neither stokers nor wood fuel are employed with conventional thermal plants of the sizes under consideration.

Table B-6 gives a breakdown by job classification of the personnel requirements of a typical 300 MW coal-fired power station. The grand total of 98 people can be considered an average for German conditions and can be reduced if such a plant is automated.

4. Power Generation with Special Fuels

The previous discussion of steam generators has been largely directed to systems firing bituminous coal, oil, or natural gas. Although the large majority of power-generating and industrial plants are using these fuels, there are significant examples of other lower grade fuels that have been and are being used. These fuels may be naturally-occurring, manufactured, or by-product fuels. These fuels are tabulated in Table B-7, according to Fryling's systemology (Ref. B-30). In the following sections, examples of steam generators that have been designed for these fuels are given.

a. Anthracite

Anthracite, in contrast with the softer bituminous coals, which contain bitumen and much volatile hydrocarbon, is a mineral that is nearly pure carbon. Some indication of the characteristics of anthracite fuels from different locales is shown in Table B-8.

Because of the hardness of this coal, slow-speed pulverizing equipment must be used to avoid uneconomical shutdowns and high pulverizer maintenance-costs. Anthracitic coals, because of their low volatility, exhibit high ignition-temperatures. Special burner and furnace design must therefore be used with this type of fuel. To maintain ignition, a combination of auxiliary fuel or refractory walls is used. Fuel is usually fired downward through arches in both front or rear walls or in both side walls. A typical example is shown in Figure B-40. Separating-type burners, in which the bulk of the carrier air is separated, produce a fuel-rich mixture which is blown into the combustion zone. The basic combustion technique is a delayed burning with low velocity air being admitted through the side walls. The low volumetric-heat-release results in a relatively long residence time and, thus, better burnout of the carbon particles.

TABLE B-5

BREAKDOWN OF CAPITAL COSTS* FOR 200 AND 400 MW BOILERS

		Bituminous Coal		Natural Gas or Oil	
		200 MW	400 MW	200 MW	400 MW
1.	Ash-handling equipment	390.7	694.0	--	--
2.	Boiler feed system	612.0	1,087.5	612.0	1,087.4
3.	Boiler plant cranes	23.5	41.3	23.5	41.3
4.	Boilers and equipment	3,470.0	6,147.5	2,896.2	5,136.6
5.	Breeching and accessories	491.8	874.3	98.4	173.5
6.	Coal-handling equipment	101.6	180.3	--	--
7.	Draft equipment	573.8	1,021.9	573.8	1,021.9
8.	Gas-burning equipment	--	--	286.9	502.7
9.	Instruments and devices	273.2	486.3	273.2	486.3
10.	Lighting systems	13.7	24.3	13.7	24.3
11.	Oil-burning equipment	--	--	429.0	751.4
12.	Pulverized fuel equipment	819.7	1,459.0	--	--
13.	Stacks	527.3	937.2	10.4	17.2
14.	Station piping	1,480.9	2,636.6	1,480.9	2,636.6
15.	Ventilating equipment	29.2	51.9	29.2	51.9
16.	Water purification equipment	215.8	382.5	215.8	382.5
17.	Water-supply systems	10.4	18.6	8.2	18.6
Grand Total		9,033,600	16,043,200	6,951,200	12,332,200

---

* Tabulated in thousands of dollars in accordance with FPC Electric Plant Account 312.

TABLE B-6

PERSONNEL REQUIREMENTS FOR A 300 MW COAL-FIRED POWER STATION (GERMAN OPERATIONS)

A) Supervision

Superintendent	1
Electrical Engineer	1
Technical assistant for heat balances	1
Shift engineers	4
Chemist	1
Laboratory personnel	5
Administrator	1
Store keeper	1
Secretary	1
Messenger	1
	17

B) Operation

Shift overseers	4
Control room operators	4
Turbine operators	4
Boiler operators	4
Feedwater and C. W. equipment operators	4
Condenser and hydrogen plant operators	4
Mills and deslagging plant operators	8
Coal plant operators	8
Deashing plant operators	4
Water treatment plant operators	4
Gate keepers	4
	52

C) Maintenance and Workshops

Workshop overseer	1
Head electrician	1
Shift mechanics	4
Shift electricians	8
Turners and millers	4
Instrument technicians	4
Welders	2
Blacksmith	1
Pipe fitter	1
Messengers	2
Janitor	1
	29

GRAND TOTAL: 98

TABLE B-7

CLASSIFICATION OF FUELS

Type of Fuel	Natural Fuels	Manufactured or By-Product Fuels
Solid	Coal	Coke and coke breeze
	Anthracite	Coal tar
	Bituminous	
	Sub-bituminous	
	Lignite	Lignite tar
	Peat	
	Wood	Charcoal
		Bark, sawdust, and wood waste
		Petroleum coke
		Bagasse
		Refuse
Liquid	Petroleum	Gasoline
		Kerosene
		Fuel oil
		Gas oil
		Shale oil
		Petroleum fractions and residues
Gaseous	Natural gas	Refinery gas
		Coke oven gas
		Blast furnace gas
	Liquified petroleum gases (LPG)	Producer gas
		Water gas
		Carburetted water gas
		Coal gas
		Regenerator waste gas

TABLE B-8

CHARACTERISTICS OF ANTHRACITE FUELS

Source	Units	Pennsylvania		Spain				Wales	Belgium	France	Korea
Moisture	%	12.5	18.3	8.00	20.00	14.0	8.0	7	4.00	8.77	12.00
Volatile Matter	%	4.8	5.0	6.30	4.15	5.4	5.5	9	9.00	5.73	4.00
Fixed Carbon	%	69.6	56.5	60.70	50.15	53.6	63.5	67	65.00	62.84	60.81
Ash	%	13.1	20.2	25.00	25.70	27.0	23.0	17	22.00	22.66	35.19
Fusion Temp. of Ash	°F	2650	-	2240	2315	2322	2550	2370	2237	2140	2800
Grindability	-	40	40	55	45	50	55	80		60	50
Heating Value (HHV)	Btu/lb	10,970	8,845	-	7,750	8,400	10,070	11,800	11,080	9,622	8,100

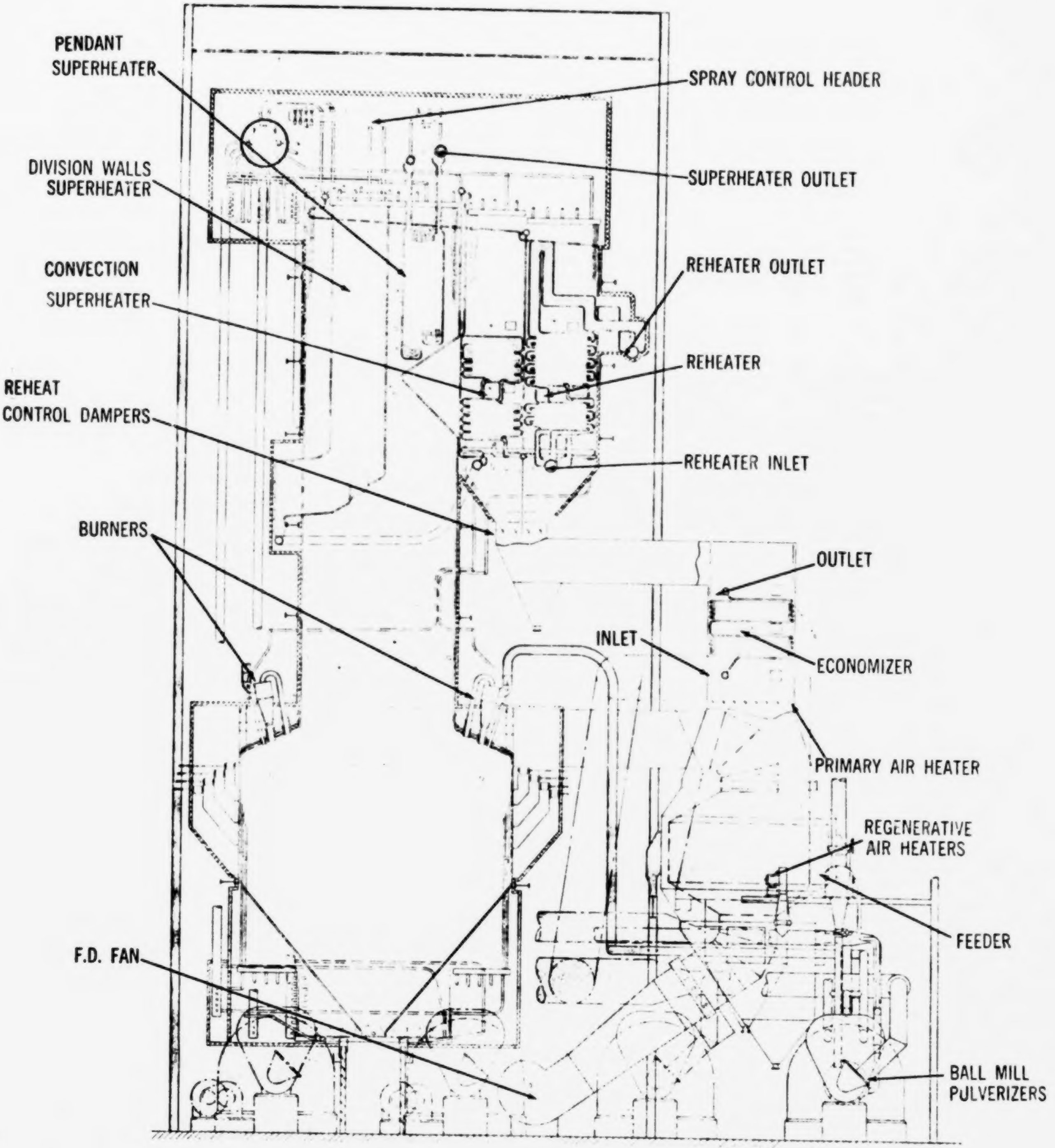

PENDANT SUPERHEATER
SPRAY CONTROL HEADER
SUPERHEATER OUTLET
DIVISION WALLS SUPERHEATER
CONVECTION SUPERHEATER
REHEATER OUTLET
REHEATER
REHEAT CONTROL DAMPERS
REHEATER INLET
BURNERS
OUTLET
INLET
ECONOMIZER
PRIMARY AIR HEATER
REGENERATIVE AIR HEATERS
FEEDER
F.D. FAN
BALL MILL PULVERIZERS

FIGURE B-40. ANTHRACITE-FIRED STEAM GENERATOR

Units have been built in the United States (Ref. B-44), United Kingdom (Ref. B-45), Spain (Ref. B-46), Belgium (Refs. B-47 and -48), and Korea (Ref. B-49). The largest single unit has a capacity of 500 MW.

b. Lignite

This material has a high moisture content and burns with a luminous, but low-temperature, flame. Because the furnace walls are subjected to a lower heat-flux, lignite-fired steam generators are larger than bituminous-coal-fired boilers of the same capacity. However, the former require less relative heat absorption to obtain the same furnace outlet temperature, which somewhat reduces the size factor between lignite- and bituminous-coal-fired boilers. However, a greater proportion of the heat must be transmitted through the convective sections of the lignite-fired furnace (Ref. B-38).

Lignites, even from the same mine, exhibit wide variations in heating value, ash fusion-temperature, and grindability characteristics. Lignites also have fouling tendencies, and great care must be taken in their use in steam generators, especially with regard to sodium content. Typical analyses are shown in Table B-9.

Lignites generally ignite readily and maintain a stable flame. Medium-speed pulverizers can be used for grinding. Typical units in operation in the United States are described in References B-50 and -51. European units typically recirculate large amounts of flue gas from the furnace to dry the pulverized lignite (Ref. B-52). All of these units have dry-bottom furnaces. Slagging furnaces are also used, however. One cyclone burner unit in operation in the United States is discussed in Reference B-53. A unique technique of burning (Ref. B-54) is incorporated into a lignite-fired unit of German manufacture located in Greece. In this unit, lignite is pulverized and conveyed to the furnace with hot air. However, part of this stream is conveyed to cyclone separators above the steam generator. The dry lignite is then fed by gravity into the furnace zone between the other lignite burners.

c. Peat

Although not a commercial fuel in the United States, countries such as Ireland, where there is little coal, use peat to a considerable extent (Ref. B-30). Large reserves of peat are also found in other countries. Typical Analyses are shown in Table B-9. Peat has been commercially fired in small steam generators either on a travelling grate or in pulverized form (Ref. B-52).

d. Wood Wastes and Waste Liquor

Starting from timber, the pulp and paper industry makes paper from the cellulose fibers, which amount to about 50 percent of this primary raw material. The wood is converted into pulp by chemical

TABLE B-9

CHARACTERISTICS OF LIGNITE AND PEAT

	Lignite			Peat		
	North Dakota		Germany	Ireland		Germany
Moisture, wt-%	36.4	36.5	50-60	40.0	45.0	32.0
Volatile Matter, wt-%	28.7	-	-	18.4	29.0	9.0
Fixed Carbon, wt-%	28.0	-	-	35.4	25.0	59.4
Ash, wt-%	6.9	6.03	10	6.2	1.0	1.6
Fusion Temp. of Ash, °F	-	2135	-	-	-	-
Grindability	-	45	-	-	-	-
HHV, Btu/lb	6,750	7,000	4,500-5,580	5,290	4,020	7,340

methods, and steam generation becomes an integral part of the operation wherein chemicals are recovered. Steam is generated by burning the wood wastes and waste liquor derived from the process. Supplementary steam and power for the conversion of pulp to paper may be obtained from power boilers burning conventional fuels, if there is an insufficient supply from bark boilers and chemical recovery units (Ref. B-30).

The chemical recovery unit was developed in the 1930's. By the 1950's, steam conditions of 600 psig and 750°F were being used. Currently, units operate at 1200 psig and 900°F. A typical steam generator is shown in Figure B-41; this design features a horizontal, continuous-tube economizer, tubular gas air-heater, and cascade evaporator. In the recovery unit, the concentrated black liquor is sprayed upon the furnace walls for dehydration prior to final combustion of the dried char on the furnace hearth. In the furnace, heat is obtained from the combustion of organic liquid constituents (dissolved from the wood). Of equal importance, the inorganic constituents (sodium salts) in the liquor are recovered as molten ash or smelt. The lower part of the furnace is actually a chemical retort. Incomplete combustion of the char in the porous bed supplies incandescent carbon and carbon monoxide, which act as reducing agents to convert the sulfate in the smelt to sulfides and sulfite. To withstand the erosive and penetrating characteristics of the smelt, special construction is used in the lower parts of the furnace walls and the floor to assure that they are leakproof as in slagging furnaces (Ref. B-32).

Wood refuse available as a fuel may consist of large pieces such as slabs, logs, and bark strips, and small pieces, such as sawdust and shavings. Furnaces for burning wood refuse are usually designed to handle chip size, in which case it becomes necessary to pass the larger pieces through a hogger or chipper. Reducing the wood to chip-size permits uniform continuous feeding, a more rapid burning of the small particles, and a more complete coverage of the grates (Ref. B-32).

Typically, wood has a heating value, on a dry basis, of 8,000 to 9,000 Btu/lb, but the moisture level may be as high as 80%. Mechanical means are generally used to reduce the moisture to about 60% for burning. Typical wood-bark has a moisture content of 40% and a heating value of 5,490 Btu/lb.

Hogged wood-refuse has successfully been burned on a thin bed. In these units the wood is blown into the furnace above a spreader stoker as shown in Figure B-42. In this manner, smaller particles dry out and burn in suspension while the remainder is burned to completion on the grate. Fly ash reinjection is often included in these units. The bark may be burned either alone or in combination with other fuels. When coal is the auxiliary fuel, the coal may be burned on the same spreader stoker, or pulverizers may be used. The choice is usually dictated by economics. In areas where fuel costs are high, the increased

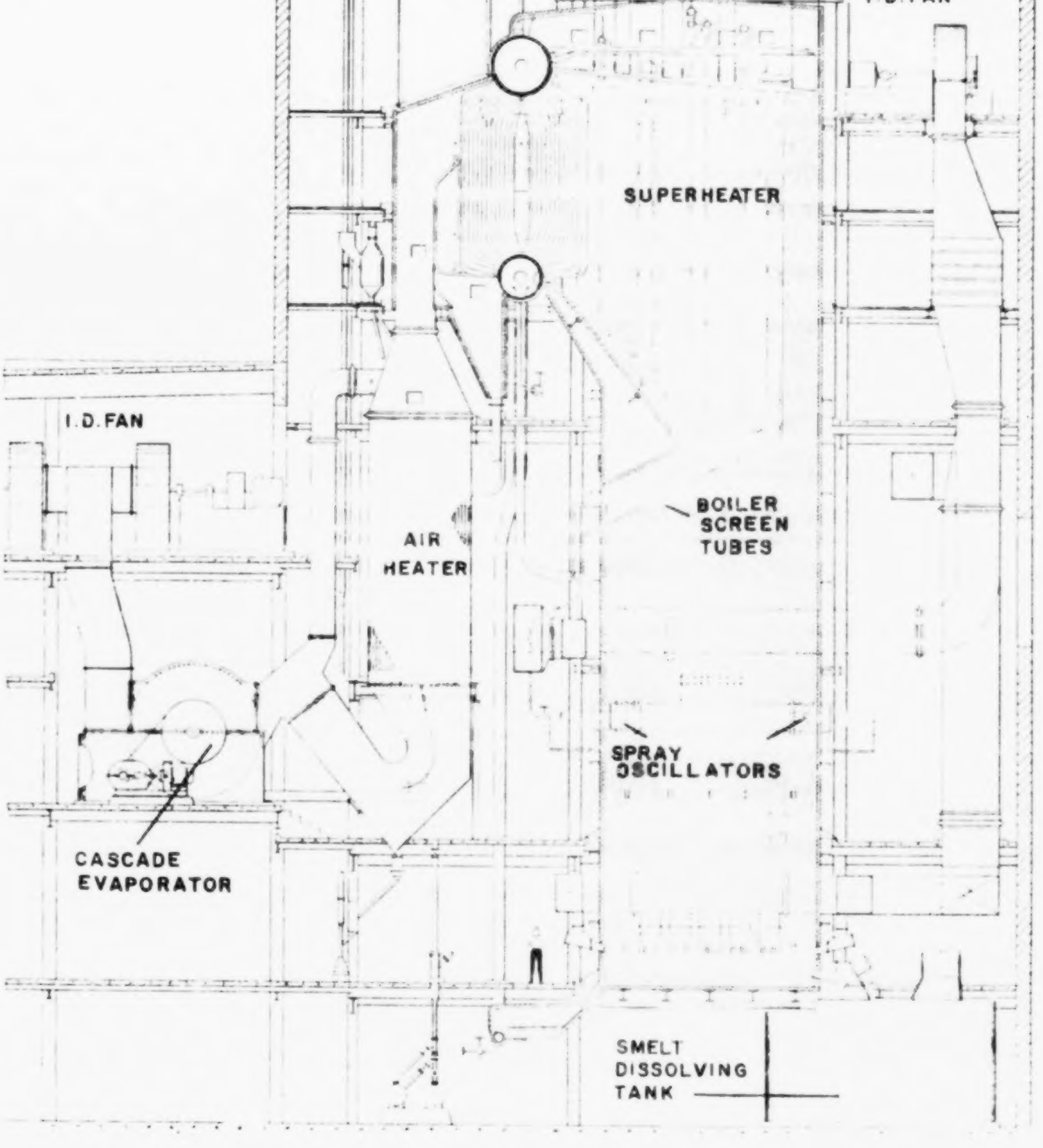

F.D. FAN
SUPERHEATER
I.D. FAN
BOILER SCREEN TUBES
AIR HEATER
SPRAY OSCILLATORS
CASCADE EVAPORATOR
SMELT DISSOLVING TANK
0
30FT

FIGURE B-41. BLACK-LIQUOR RECOVERY UNIT

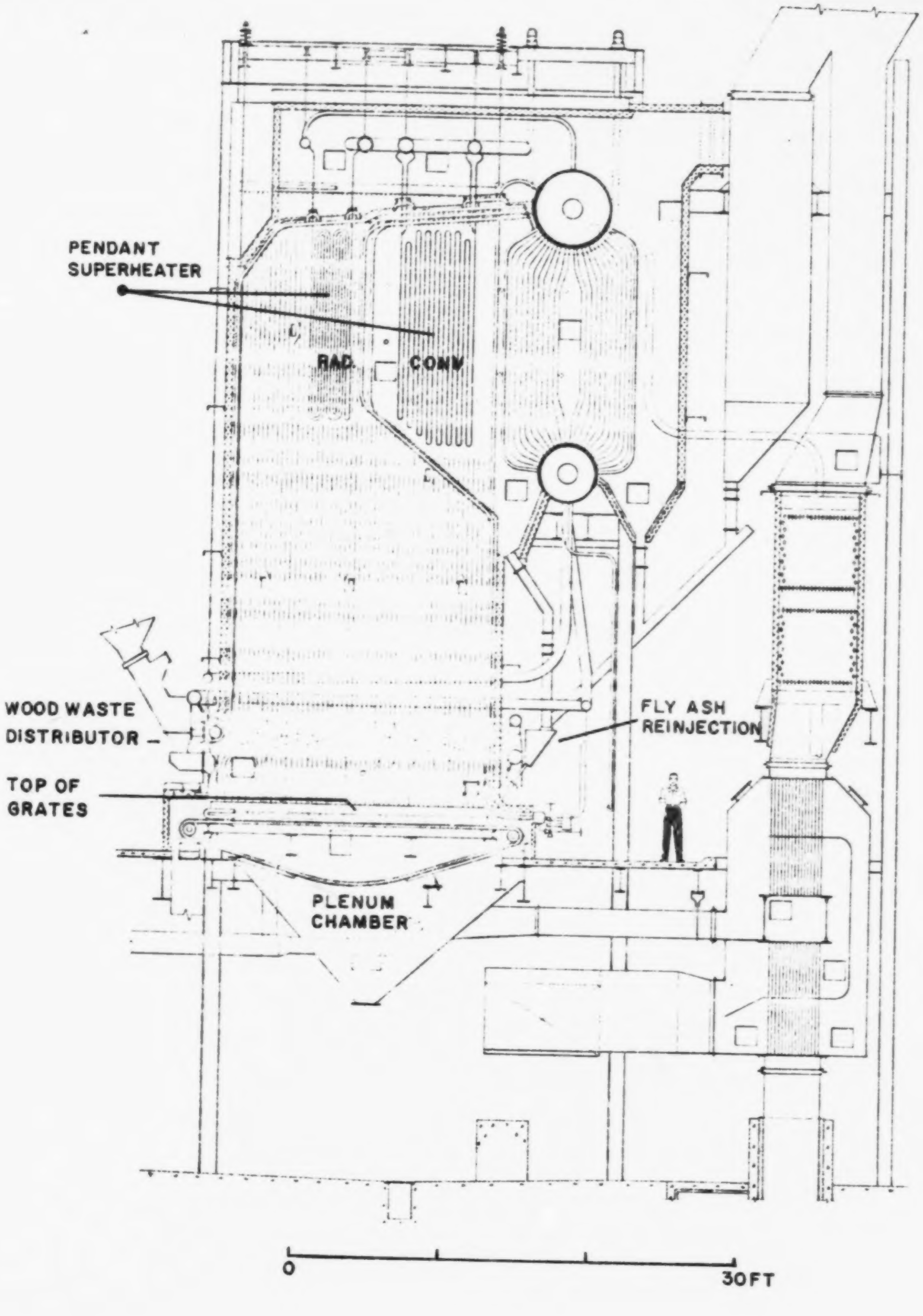

PENDANT SUPERHEATER
RAD.
CONV
WOOD WASTE DISTRIBUTOR
TOP OF GRATES
FLY ASH REINJECTION
PLENUM CHAMBER
0
30FT

FIGURE B-42. WOOD-WASTE-FIRED STEAM GENERATOR WITH SPREADER STOKER boiler efficiencies that can be realized with pulverized coal will generally offset higher first-cost. Other conditions, such as use-factor, purchased-power costs, proportions of fuels to be burned, steam conditions, and steam-flow variations, will also affect the choice of the coal-firing method (Ref. B-30). One large-sized, combined-fired unit has a steam capacity of 450,000 lb/hr at 1335 psig and 958°F when burning natural gas and bark.

Another type of continuous-feed, waste-wood-fired steam generator is shown in Figure B-43. This unit (Ref. B-55) is designed for combined firing and features an inclined, water-cooled grate. The designed capacity is 50,000 lb/hr of wood waste (60% moisture) with supplemental oil or gas to produce steam conditions of 600 psig and 700°F.

A steam-raising furnace using suspension-fired pulverized coal and hogged bark as fuel is in operation at Muskegon, Michigan. This furnace generates 275,000 lb steam per hour, which is used, in conjunction with steam from other boilers, for production of electricity for in-plant use. Of the 20 MW power requirement for the facility, a large production plant for high-grade printing paper stocks and container cardboards, only 2 MW's need be purchased from the local utility. Nominal design of the unit is 48,800 lb/hr of bark (4500 Btu/lb) and 23,800 lb/hr coal, but bark availability usually limits this fuel to 12,000 to 15,000 lb/hr.

Bark is passed through a single stage hogger, with typical particle size distribution (wt-%) of the effluent being as follows:

Screen	Description	Softwood	Hardwood
+ 1-in.	Long fibrous strands	2.6%	10.4%
+ 3/4-in. - 1-in.	2- to 3-in. strands	2.5	5.1
+ 1/2-in. - 3/4 in.	1- to 2-in. strands and large chips	5.6	13.8
+ 1/4-in. - 1/2 in.	Short strands and chips	16.3	19.1
+ 1/8-in. - 1/4-in.	Small curds	12.6	13.4
- 1/8-in.	Fines	60.4	38.2

This material is conveyed to a live-bottom silo where the small quantity of sawdust from the mill is admixed. From here it is moved to a distributor for equal division to four pneumatic blowers. Even though Teflon coated, the distribution system tends to become fouled with resins from the wood and unequal quantities of bark are fed to the blowers. This is believed to be the cause of the minor buildup of burning wood on the grate; a superior means of distribution is being sought. The blowers transport the bark approximately 150 ft to the furnace, where it is introduced through a 6-in. pipe tangentially between two corner coal guns; an oil system is also available.

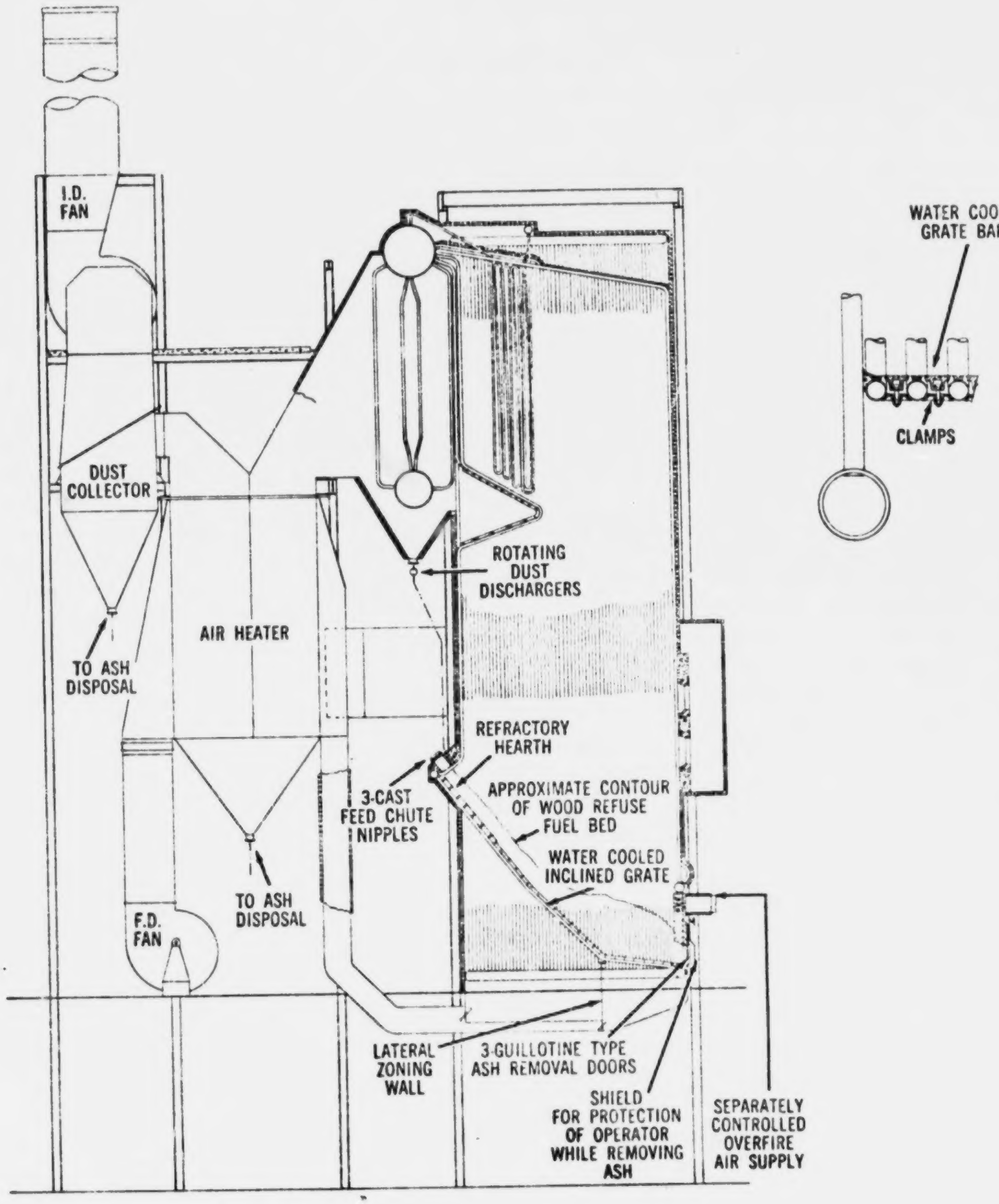

I.D. FAN
DUST COLLECTOR
TO ASH DISPOSAL
AIR HEATER
F.D. FAN
TO ASH DISPOSAL
ROTATING DUST DISCHARGERS
REFRACTORY HEARTH
APPROXIMATE CONTOUR OF WOOD REFUSE FUEL BED
3-CAST FEED CHUTE NIPPLES
WATER COOLED INCLINED GRATE
LATERAL ZONING WALL
3-GUILLOTINE TYPE ASH REMOVAL DOORS
SHIELD FOR PROTECTION OF OPERATOR WHILE REMOVING ASH
SEPARATELY CONTROLLED OVERFIRE AIR SUPPLY
WATER COOLED GRATE BARS
CLAMPS

FIGURE B-43. WOOD-WASTE FIRED STEAM GENERATOR WITH INCLINED WATER-COOLED GRATE

Visual observation of the furnace indicates all but a small fraction of the bark burns in suspension. At times, a buildup of some 3-ft in height occurs in the corners of the 12-ft^2 grate, located some 20 ft below the pneumatic guns, at which time the pile topples and permits combustion to be completed. Consideration is being given to addition of small diameter air jets above the grate to minimize fuel buildup in stagnant areas.

Separate measurement of bottom ash and fly ash is not made, but it is claimed that the former is only a very small percentage of the total. A material balance has not been attempted. Carbon content of the over-ash has been found to run as high as 10 to 12%.

The paper company regards this unit, the only steam generator now in operation that is tangentially fired with waste-fuel, as a definite success.

As with most fuels, a careful study of the ash from coal and bark should be made, especially if both are to be fired on the same grate. It has been shown that initial deformation, softening, and fluid temperatures of proportional amounts of coal and bark ash will vary in an unpredictable manner. Figure B-44A illustrates a fractional analysis considered acceptable for simultaneous firing. Figure B-44B illustrates an incompatible mixture (Ref. B-56). This criterion would also apply to some degree to combined bark/pulverized-coal firing, since slagging in the furnace and convection sections is rather limited.

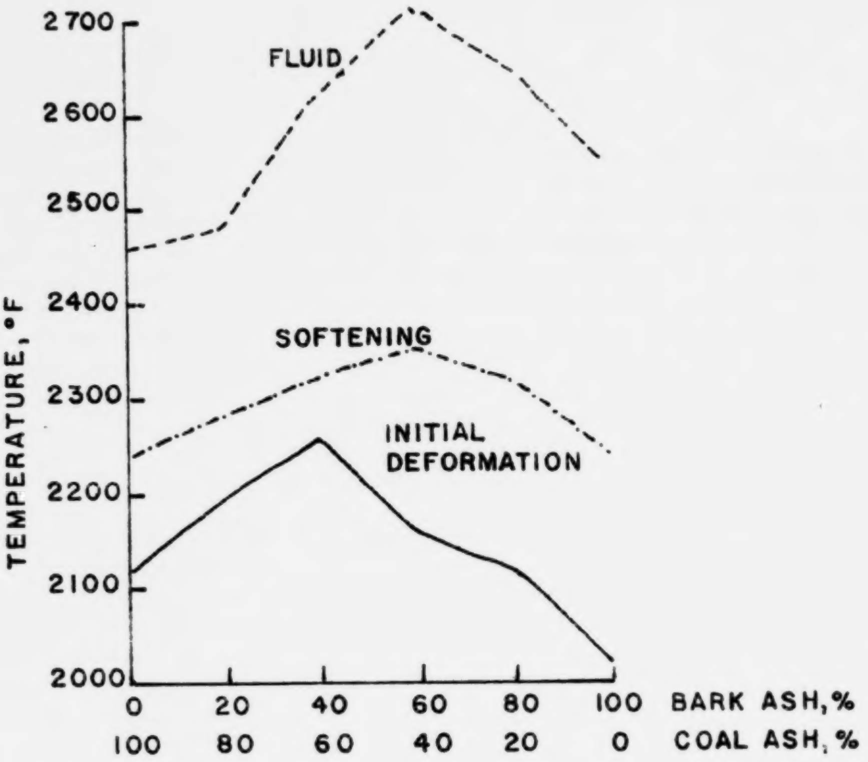
e. Bagasse

This waste material has been utilized commercially in relatively small steam generators. In some cases, bagasse is burned in batches on hearths. In general, however, it can be stoked into furnaces of essentially the same design as used for waste-wood firing. A design very similar to that shown in Figure B-43, for example, has been used for bagasse-firing. Units are also under construction which will operate on the principle of tangential waste-fuel injection. Where copious fuel supplies are available year around, it is possible to operate bagasse-fueled boilers without resorting to combined-firing.

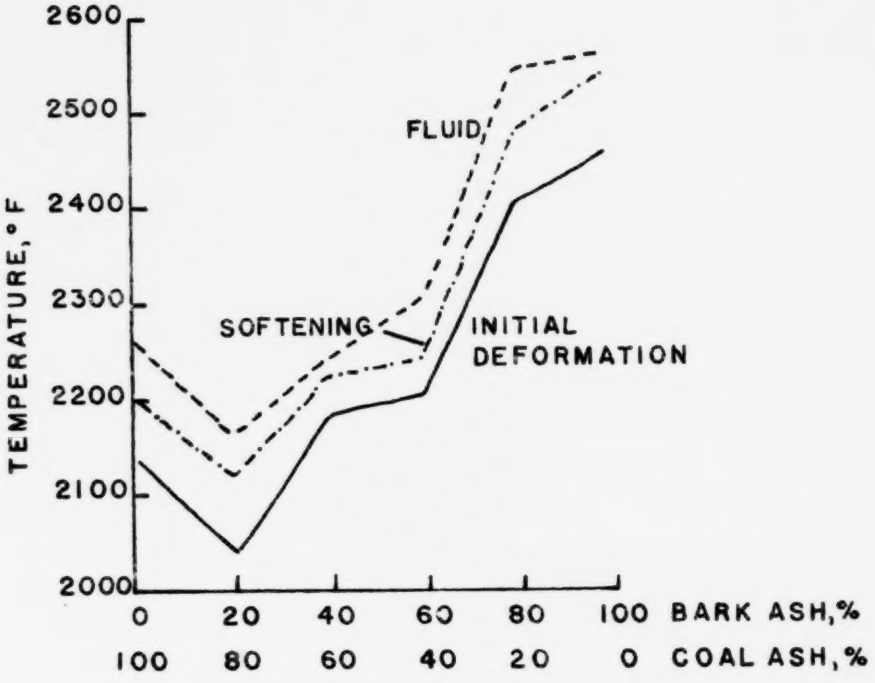
5. Applications for Refuse-Firing

a. Steam Cycles

As a waste fuel, refuse does not have the desirable properties of fossil fuels. It has a high ash and moisture content. However, its combustible portion is rather volatile.



A. COMPATIBLE MIXTURES



B. INCOMPATIBLE MIXTURES

FIGURE B-44. FUSION TEMPERATURES OF BARK/COAL ASH MIXTURES

In projecting how refuse may be exploited for power generation, utilization of its energy has been considered separately and in combination with coal for various portions of the steam cycle, including feedwater heating, boiling, superheating, and reheating (Refs. B-57 to B-72)*. It was considered and rejected as the sole fuel for feedwater heating, boiling, and superheating, wherein the steam generated would be combined with the outputs of conventionally fired units in a common manifold for expansion in several turbines (Refs. B-63 to B-65). The basis of rejection was the wide variations in steam-flow rates and the prevalent domestic practice of connecting the steam lines between the steam generator and the turbine directly.

b. Firing Methods

Various methods of burning refuse either alone or in combination with coal have been practiced and proposed (Ref. B-66). An early method was the burning of "as received" refuse with conditioning of oversized refuse on a stoker. Travelling grates were largely rejected due to their inherent inability to agitate the refuse. Agitating grates such as backward or forward reciprocating grates may be considered as a generic type on the basis of their utilization for solid fossil-fuels as well as refuse. The roller grate was developed solely to burn refuse, although its handling and burning characteristics and performance are similar to reciprocating grates.

Utilization of this type of steam generator has been largely confined to European municipalities, particularly in West Germany. An example of a domestic unit of this type, the first constructed (1965) in this country, is shown in Figure B-45. This unit is equipped with a reciprocating grate and incorporates a supplemental oil-firing capability. Unlike the European counterparts, which are typically coupled with turbines, this unit operates at steam conditions (275 psig and 415°F) intended for ship-service lines on nearby Naval docks (Ref. B-59 and -67).

Spreader stokers have been considered, not only on the basis of their utilization with solid fossil-fuels, but with such waste fuels as hogged wood-bark (Refs. B-30, -32, and -56). This type of stoker is presently being considered for burning refuse, which has been conditioned to a nominal 4-in. top size (Refs. B-68 and -69). Shredding not only produces a more uniform sizing but also helps distribute (and somewhat reduce) the moisture. It thus tends to make a heterogeneous fuel more homogeneous, at least on a macroscopic basis.

Recent experience has indicated that size reduction results in a significant increase in the burning rate of refuse. At Plaquemine Parish, Louisiana, it has been reported that the use of refuse-grinding

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*See Section V of this Appendix.

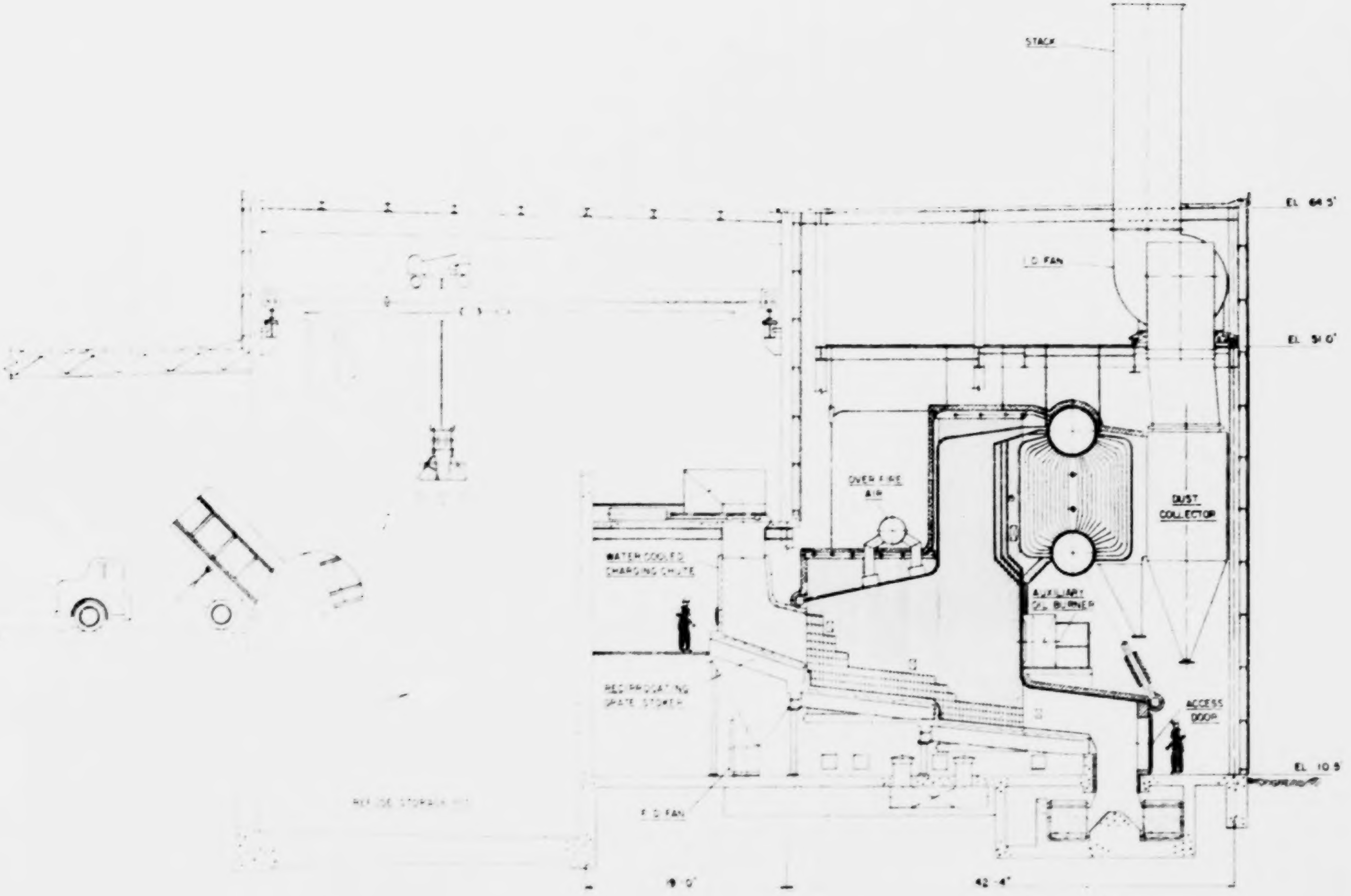
STACK
I.D. FAN
EL 64.5'
EL 51.0'
DUST COLLECTOR
OVER FIRE AIR
AUXILIARY OIL BURNER
ACCESS DOOR
EL 10.5'
WATER COOLED CHARGING CHUTE
RECIPROCATING GRATE STOKER
REFUSE STORAGE PIT
F.D. FAN
19'-0"
42'-4"

FIGURE B-45. REFUSE-FIRED STEAM GENERATOR equipment has led to a firing rate increase of from 2100 to 6000 lb/hr. The material is stoked onto travelling grates. This small installation is a refractory-wall incinerator, however; whether similar benefits could be expected from a steam-raising unit is uncertain.

A further step in this direction is the suspension type of burning*. In this method, refuse is conditioned to a nominal 2-in. top size, or smaller, and blown into a furnace. As the refuse falls, high velocity air jets tend to create a high degree of turbulence. In this method, a grate at the bottom of the furnace may be essential for complete burnout of the refuse. Interest in this method is based on its previous utilization for waste fuels such as wood bark (see above and Ref. B-56), which is now also being extended to refuse (Refs. B-70 to B-72).

Another system for suspension burning is the arch furnace. This configuration employs no moving grate. This method has been considered on the basis of its successful utilization with low-volatility, solid fossil-fuels (e.g., anthracite; see Figure B-40). While refuse is unlike low volatile fuels having high ignition temperatures, such as anthracite, this method provides a considerable residence time in which to promote the complete burnout of the fuel. In this method, air is injected along the trajectory of the burning fuel particles, providing a streamline flow to the convection sections of the steam generator. It is reasonable to expect that the refuse-input of an arch-furnace unit will be at least twofold greater than the maximum allowable for a grate-equipped furnace of the same size.

Slagging furnaces have been discussed earlier in terms of their operations with solid fossil-fuels and also as chemical recovery units in pulping plants. This type of firing is presently being tested for burning refuse (Refs. B-73 and -74).

In this context, the evaluation of the basic input-data available raises several serious technical questions. While the prototype units are of small capacity, it would appear that pool capacities would be small and not readily adaptable to the large-sized pools deemed to be essential for large capacity steam generators. Critical properties for slagging furnaces are viscosity and melting-temperatures, reported to be between 2600° and 3200°F. The absolute values of these properties must be known with some degree of precision and these values should not vary greatly. Ash-melting temperatures, however, are quite dependent on the levels of the constituents present (Ref. B-75). The experience with chemical-recovery units has been marked with episodes of tube corrosion; this same potential exists for refuse-firing in slagging units (Ref. B-76 and -77). It would appear that a firing method, shown to be unfavorable with a homogeneous fuel, should be an unlikely candidate for power generation when firing a heterogeneous (variable-ash) fuel.

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*See Section III, B, 4 of Volume I.

c. Power Output Fluctuations

Power output from a system using refuse as a fuel will fluctuate due to the highly heterogeneous nature of refuse. Several different methods are used in Germany to prevent the power-output from fluctuating to an extent that it cannot be handled by the system. These methods are:

- Selective loading of refuse bunkers to obtain a good mixture of the available types and qualities of refuse.
- Constant mixing in the bunkers, usually by means of the charging cranes, to increase the uniformity of the mixture.
- Oil-firing to support the incineration of refuse.

Oil firing is not required to stabilize the power output in all cases. The neighboring power stations and system distribution networks often compensate for fluctuations that occur. The control concept that one German manufacturer (Ref. B-78) recommends for refuse-burning power plants is to equip the turbines with initial-stage pressure regulators.

IV. AIR POLLUTION CONTROL

A. NATURE OF EMISSIONS

1. Gross Products of Combustion

Because 10 to 12 lbs of gaseous products are typically formed per lb of fuel burned, the combustion of fossil fuels for power generation requires the handling of enormous quantities of gas. Although a precise determination of reaction products is normally made by a molecular balance based on the ultimate fuel analysis, reliable approximations can be derived from the as-fired heating value of the fossil fuel and the observed values of theoretical air required to combust a specific equivalent of Btu's available in that fuel. The weight of theoretical air required per 10^4 Btu has been tabulated (Ref. B-32) for fuel oil (7.46 lb), natural gas (7.20) and coal. In the last case, the value can be taken from a graph on which theoretical air is plotted against the percent of volatile matter in the coal (dry, ash-free basis). As a rough approximation, the weight (lbs) of theoretical air required per lb of fossil fuel is equal to the as-received heating value (Btu/lb) of the fuel divided by 1300.

As will be shown, the total gas-volume is a critical parameter in the selection and design of air pollution control equipment. A statistical average of design gas-flows for power-generating boilers, based on net megawatt output, is shown in Figure B-46.

2. Particulate Emissions

Approximately 80% of the potential ash in pulverized coal is released and entrained as fly ash in the suspension-burning process. This is reduced to a probable value of less than 20% for the special case of grate-burning of coal, although the amount of ash transported in the flue gas is strongly influenced by the grate air-velocity. Not all of the fly ash entrained in the flue gases can be identified as normal components of the fuel ash. Some of the particulates are unburned fuel and acidic smuts, containing reaction products of the interior furnace/boiler surfaces. Generally speaking, however, the chemical properties of the particulates are determined by the specific composition of the fuel. A typical analysis of fly ash from a coal-fired unit might include: 20% Fe_2O_3, 15% (or less) Al_2O_3, and 30% SiO_2. The remainder would consist largely of CaO, MgO, TiO_2, and various sulfates. Of the sulfur introduced into the coal and/or oil combustion* reactions, less than 5% becomes deposited as sulfur compounds in the fly ash.

a. Particulate Levels

Reliable statistical correlations between particulate concentrations and the ash content of coal have been reported (Ref. B-79) for suspension-fired (pulverized coal) and cyclone (crushed coal) furnaces. These are shown in Figures B-47 and -48. Even finer (unpublished) correlations have been made between the particulate concentration and the ash equivalent per 10^4 Btu. Ash/particulate concentrations for stoker-fired units have not been well correlated, due to gaps in reinjection data and underfire-air relationships.

Similarly, particulate concentrations for oil-fired units have not been well-defined. Due to the low ash-content of oils, the particulate problem associated with large oil-fired units is usually caused by acidic smuts. These arise due to localized (SO_3-condensation caused) corrosion that results in the formation of metallic sulfates. These sulfates become adsorbed on carbonaceous fly ash particles; the resulting smut and soot fall-out thus constitutes the nuisance identified with oil-firing. The actual ash and unburned matter, being extremely fine, also causes a plume-opacity problem. Overall particulate concentrations from large oil-fired units are very low, being on the order of 0.1 to 0.2 grains/SCF (Ref. B-80 and -81). Small, through intermediate-sized, oil-fired boilers, with their

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*Natural gas usually contains little or no sulfur.

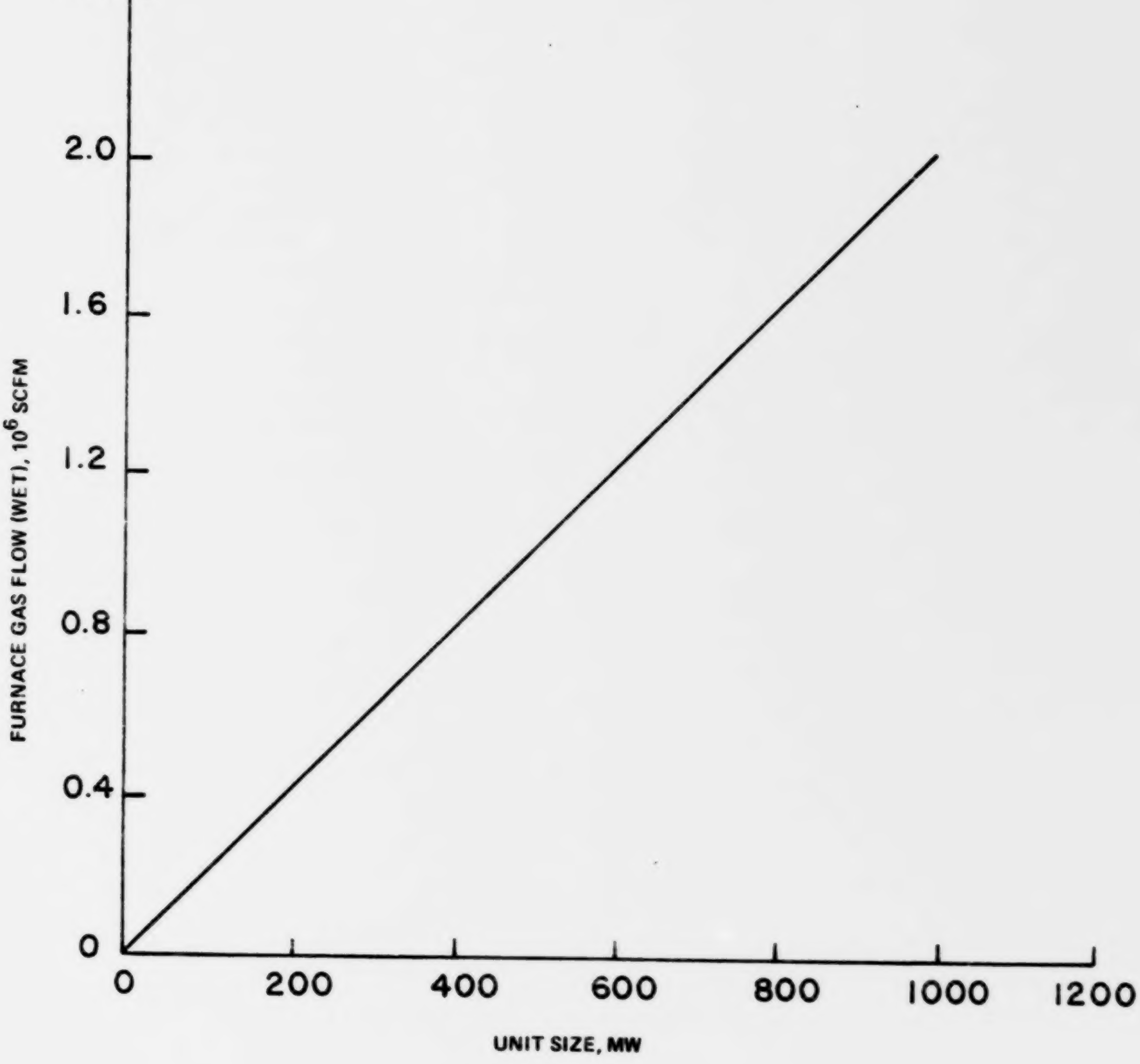

FIGURE B-46. GAS FLOW VS GENERATOR OUTPUT

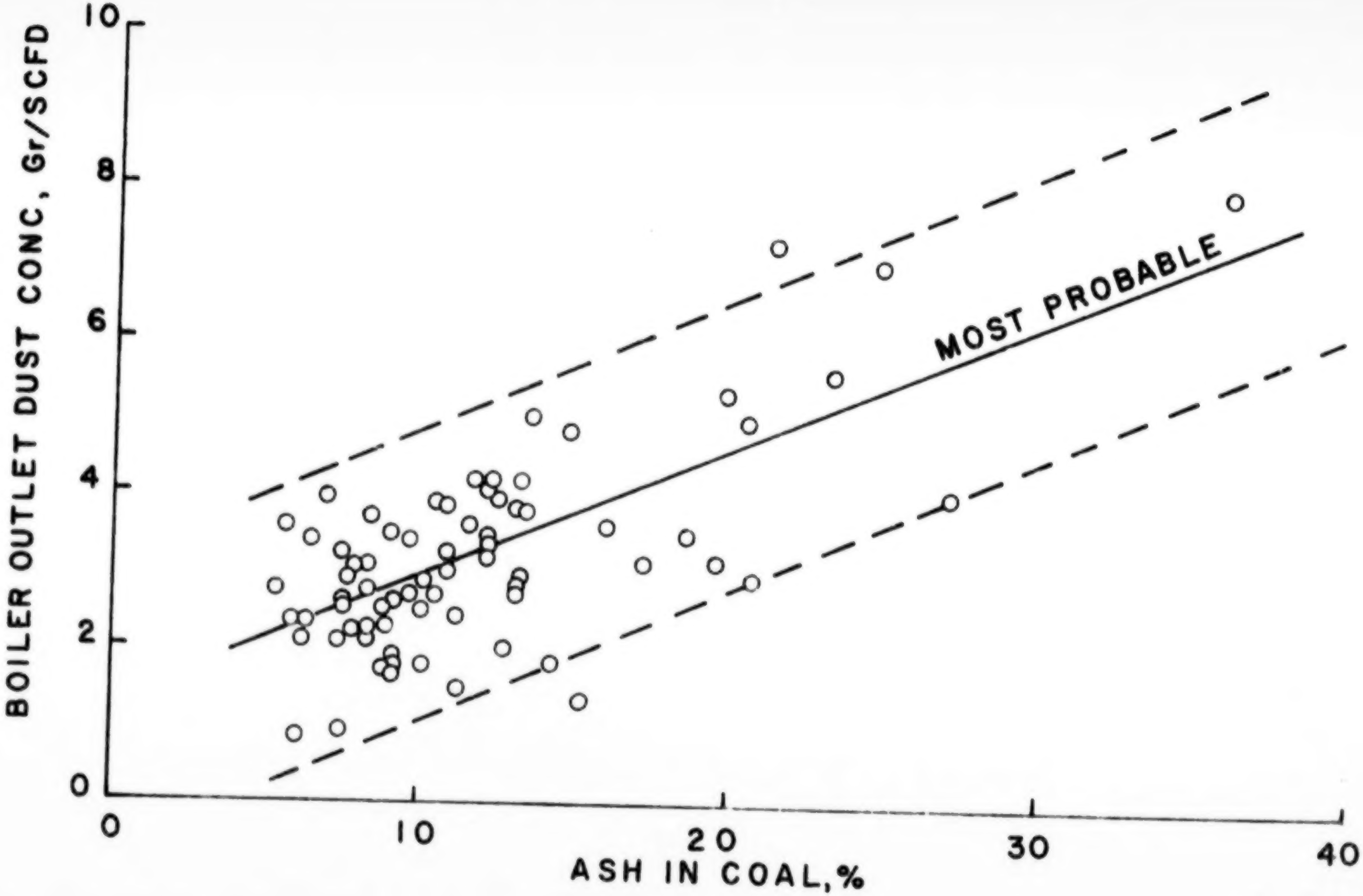

FIGURE B-47. DUST CONCENTRATION: SUSPENSION-FIRED FURNACE

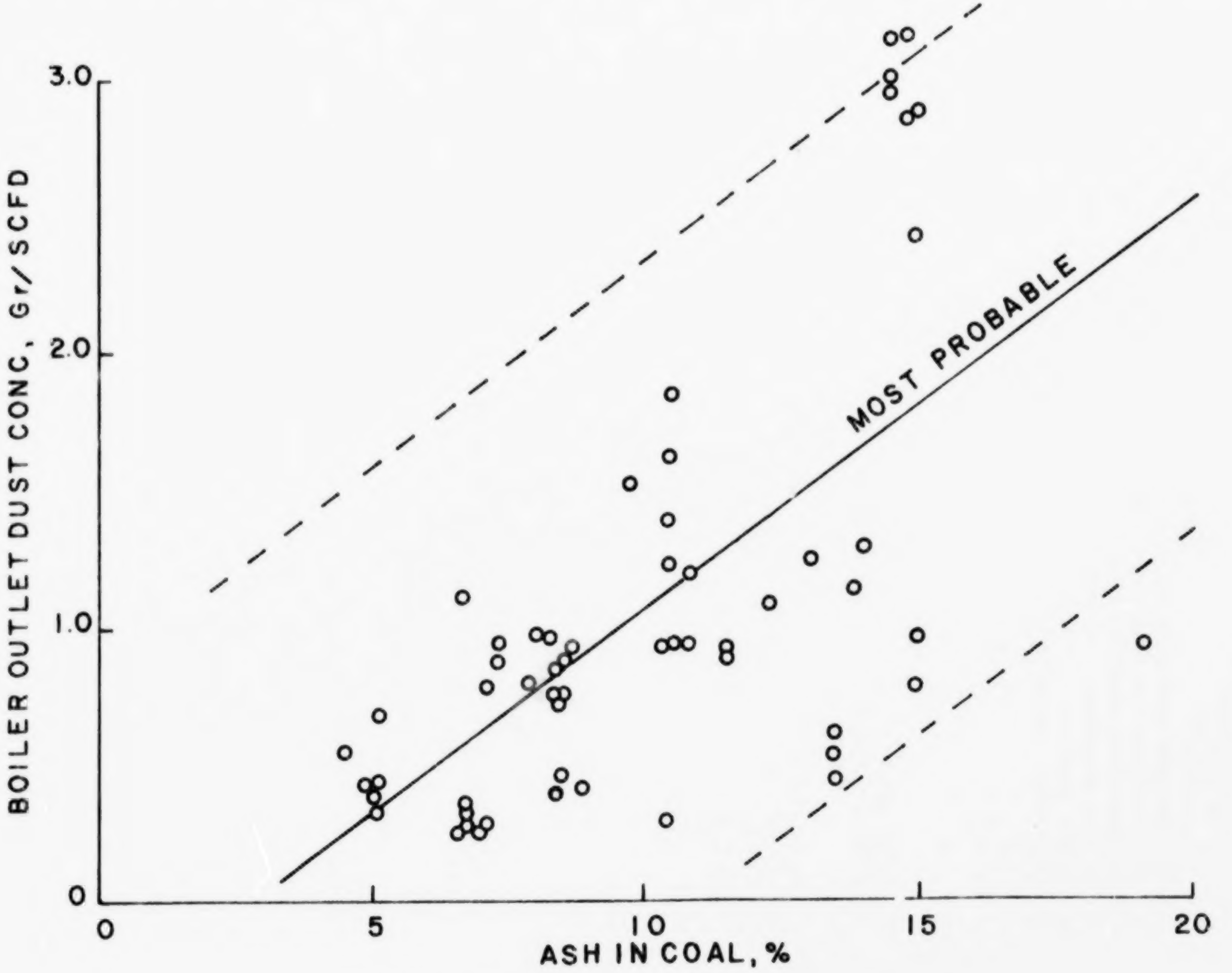

FIGURE B-48. DUST CONCENTRATION: CYCLONE FURNACE inherently lower combustion-efficiencies, produce effluents with slightly higher particulate concentrations. In all unit sizes, the introduction of magnesium-based additives about doubles particulate output. These additives are commonly used to reduce superheater corrosion and air heater pluggage. There is recent evidence (Ref. B-82) that such additives enhance overall system performance of the electrostatic precipitation process.

b. Physical Properties

(1) Particle Size Distribution

Data on particle size distributions have been published (Ref. B-79) for suspension-, cyclone-, and stoker-fired boilers, as shown in Figures B-49 through B-51, respectively.

Due to the physical instability and the hygroscopic nature of oil-derived fly ash, reproducible determinations of particle size distributions are difficult to achieve. Data have been reported (Ref. B-83) which indicate that a relatively coarse particle ($60\% > 10\mu$) is found in the flue gas of oil-fired boilers. Tar camera data, photomicrographed glass-impaction-slides, and field tests on mechanical collectors (Refs. B-80 and -81) indicate that a much finer material exists ($90\% < 1\mu$) in situ.

Table B-10 furnishes a summary of particulate concentrations and size distributions for various fossil fuel combustion systems.

(2) Density and Specific Gravity

Apparent, or bulk, densities of fly ash, which are only employed in sizing hoppers, bunkers, or silos, can range from 20 to 120 lb/ft^3. Actual or true specific gravities are required, together with particle size data, for selecting inertial particle collectors. For coal fly ash, true specific gravities range from 1.2 to 3.2. Reliable values for oil-derived ash have not been reported, presumably because of the instability problem mentioned earlier. Freshly collected oil-ash is very light and fluffy, suggesting a low bulk-density.

(3) Bulk Resistivity

Bulk Resistivity of fly ash is an important design parameter in the consideration of electrostatic precipitators. Absolute values have been published (Ref. B-84) and the Government is sponsoring several programs (Refs. B-85 and -86) in which the in situ determination of resistivities of fly ash from coal-fired boilers is being determined.

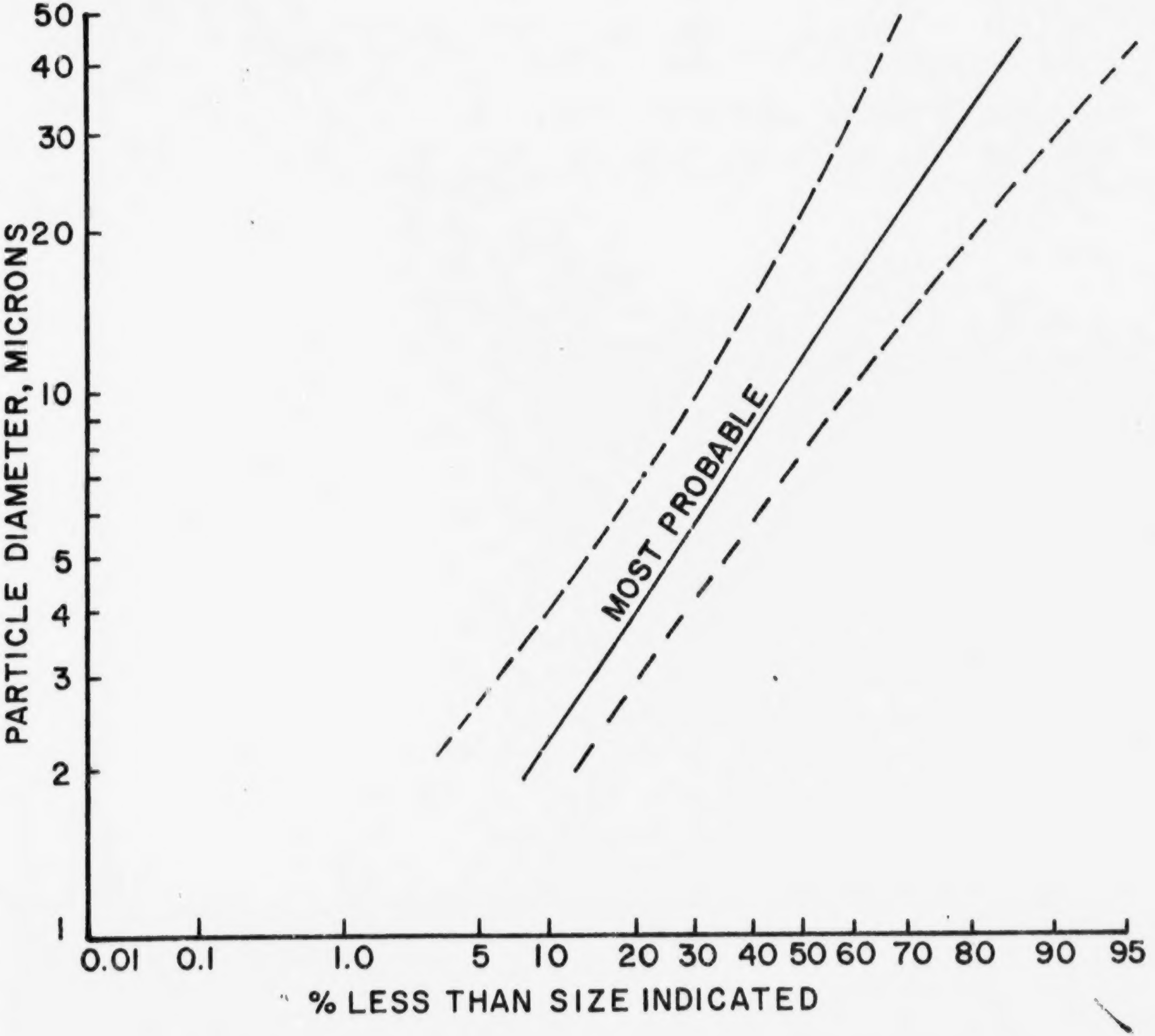

FIGURE B-49. SIZE DISTRIBUTION OF FLUE-GAS PARTICLES - PULVERIZED COAL FIRED IN SUSPENSION

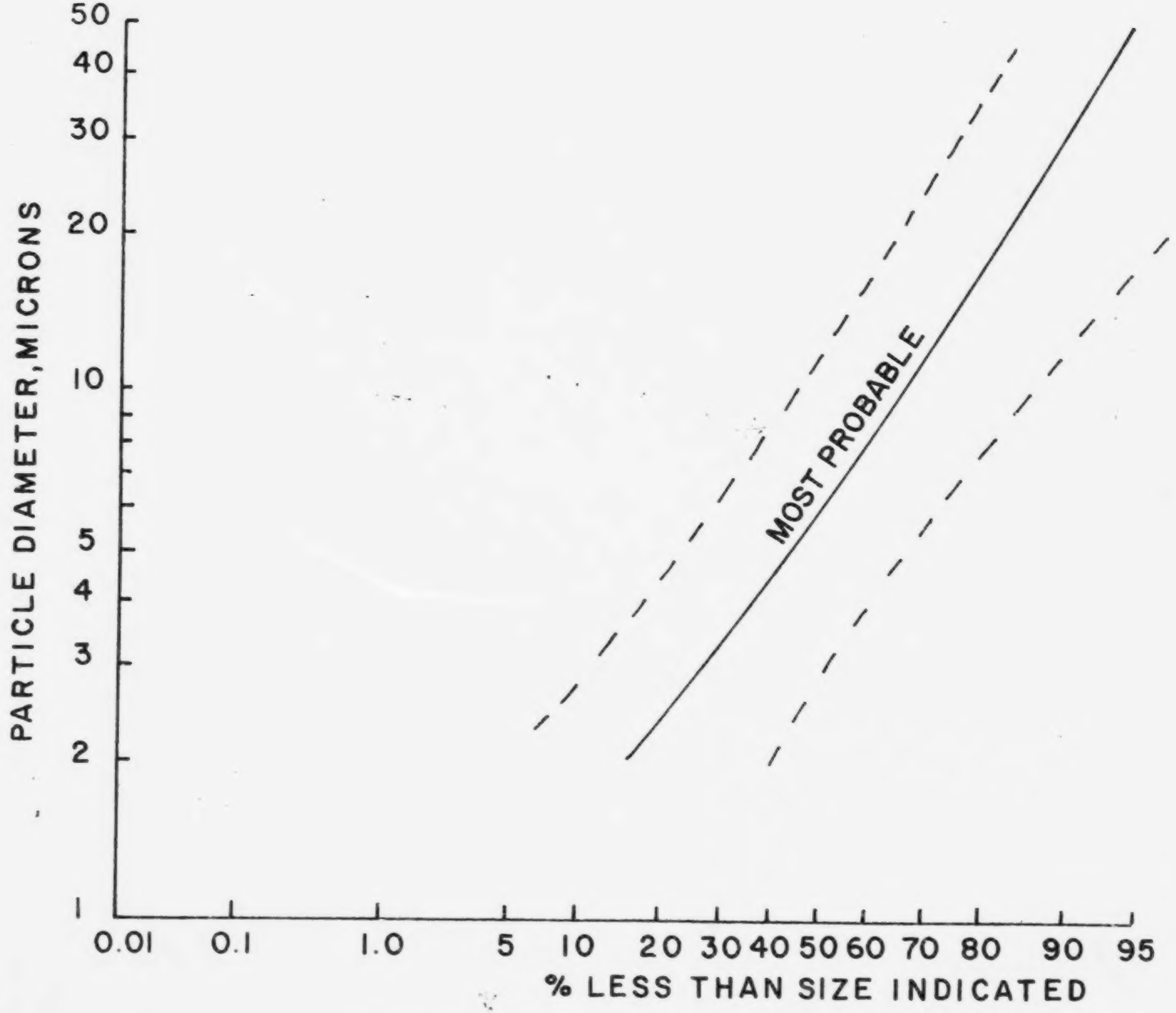

FIGURE B-50. SIZE DISTRIBUTION OF FLUE-GAS PARTICLES - CRUSHED COAL FIRED IN CYCLONE FURNACE

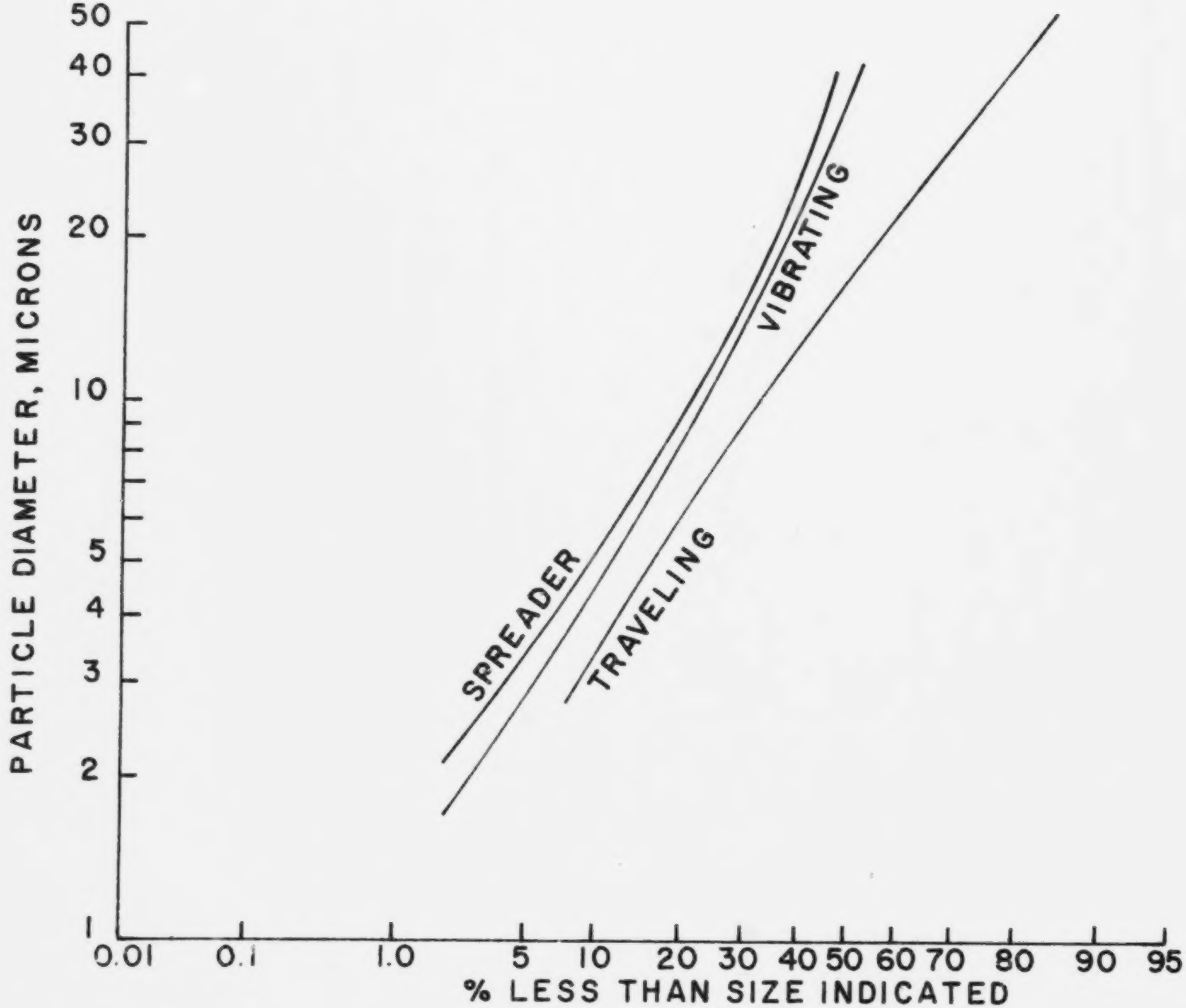

FIGURE B-51. SIZE DISTRIBUTION OF FLUE-GAS PARTICLES - COAL FIRED ON GRATES

TABLE B-10

SUMMARY OF PARTICLE EMISSION DATA

	Boiler Emissions				Particle Size Distribution	
	Grains/SCFD[1]		% of Coal Ash		%<10 microns	
Type of Firing	Avg.	Max.	Avg.	Max.	Average	Finest
Pulverized Coal	2.9	3.9	80	120	44	58
Cyclone	1.0	1.7	28	47	65	72
Stoker	--	--	--	--	23	30
Reinjection:						
None	1.0	--	28	--	NA(2)	NA
100%	4.0	--	110	--	NA	NA
Partial	1.0	--	28	--	NA	NA
Oil-Fired						
Intermediate (> 150 MW)	0.1	0.2	--	--	90(3)	--
Small (<100 MW)	0.15	0.3	--	--	90	--

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1) Based on average of 10% ash in coal

2) NA = Not Available

3) Probable *in situ*

Relative resistivity vs temperature data for fly ash of suspension-fired coal of varying sulfur content have also been reported (Ref. B-87). Figure B-52 illustrates this relationship. The decrease in fly-ash resistivity with increasing coal sulfur-content is attributed to the concomitant variation in SO_3 levels. A portion of the reaction products of SO_3 are absorbed on the fly ash and cause the surface conductivity to increase. Thus, as the sulfur content of the coal and the SO_3 level in the flue gas increase, the resistivity of the fly ash will decrease. This also explains why, in applying flue-gas desulfurization processes in which fly ash is not removed (e.g., dry limestone or dolomite injection), the efficiency of an electrostatic precipitator will be reduced.

The combustible carbon-content of the fly ash, which is largely determined by the screening or sizing of the fired coal and the combustion efficiency of the furnace, also influences resistivity. The chemical composition, notably the alumina and magnesia content, also plays an important role. The following table illustrates this for two ashes from coals having identical proximate analyses:

RELATIVE FLY ASH ANALYSES

	Proximate Analysis Coals A & B As Fired	Proximate Analysis Coals A & B Dry Basis		Ultimate Analysis Ash A %	Ultimate Analysis Ash B %
Moisture, %	14.2	0	Fe_2O_3	14.2	6.4
Vol. Matter, %	35.2	41.0	Al_2O_3	20.0	32.6
Fixed Carbon, %	45.8	53.4	SiO_2	28.2	38.7
Ash, %	4.8	5.6	CaO	23.8	9.86
Sulfur, %	0.45	0.53	MgO	5.04	1.43
			SO_3	2.83	0.88
Bulk Resistivity @ 300°F, Ohm-cm				3×10^{11}	2×10^{13}

Finally, moisture is an agent that will greatly increase surface conductivity. This is demonstrated in Figure B-53, which was published by White (Ref. B-84).

3. Gaseous Emissions

On an average basis, the gaseous products of fossil-fuel combustion will include approximately 6% moisture for coal and oil (slightly higher for gas), 12% CO_2, 6% O_2, and the balance N_2. This is based on 20% excess-air operation. The principal gaseous pollutants include:

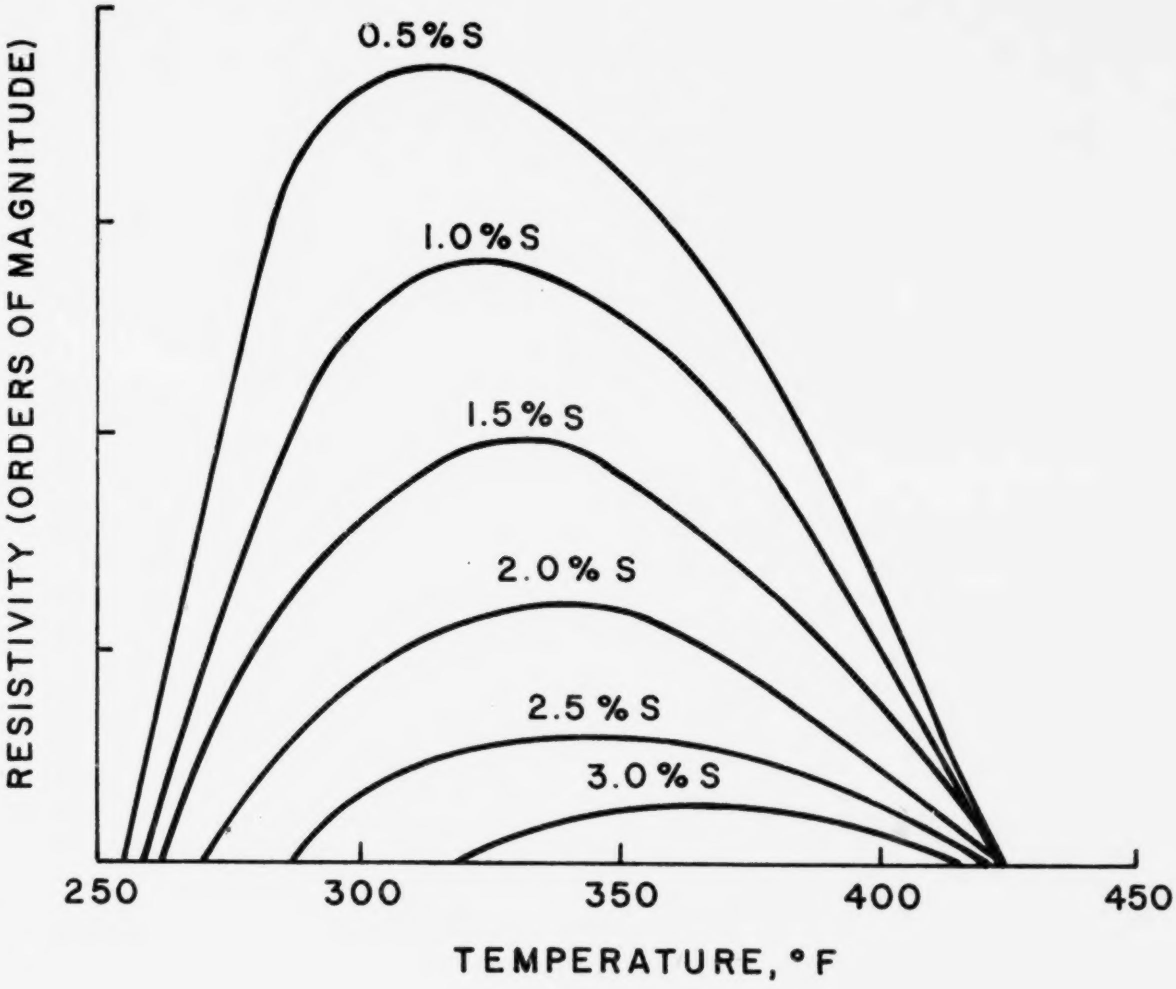

FIGURE B-52. RELATIONSHIP OF FLY ASH RESISTIVITY TO COAL SULFUR-CONTENT

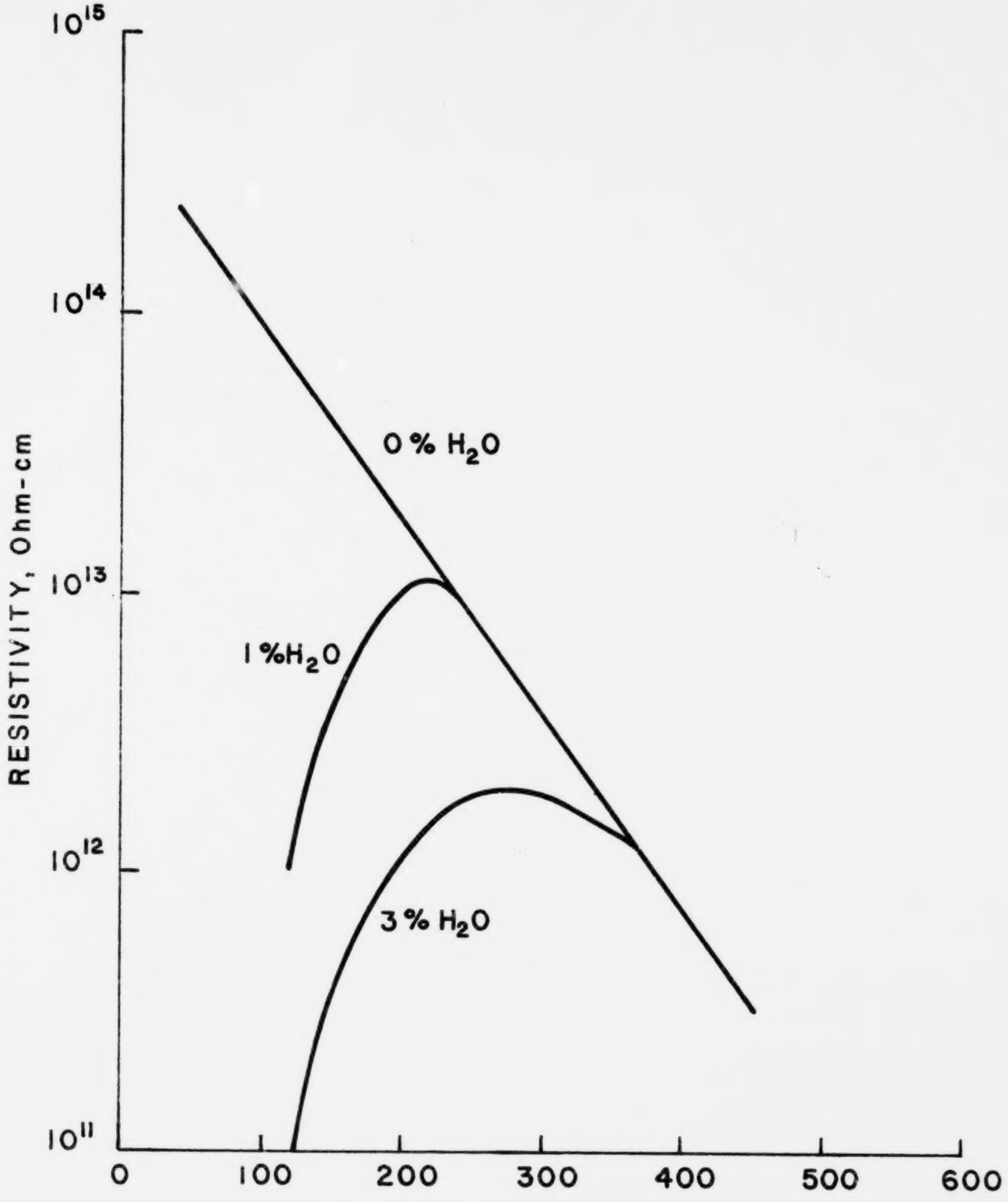

FIGURE B-53. EFFECT OF FLY ASH MOISTURE CONTENT ON RESISTIVITY

- Sulfur Oxides (SO_2, SO_3)
- Nitrogen Oxides (NO_x)
- Carbon Monoxide (CO)
- Hydrocarbons

Average values for these compounds in stack gases of coal-fired power plants have been reported (Refs. B-88 and -89) and are tabulated in Table B-11.

a. Sulfur Oxides

The oxidation to sulfur dioxide of sulfur-containing compounds in fossil fuels readily goes to completion. Further oxidation to SO_3 occurs to a small extent. As shown in the following table (Ref. B-81), the fossil fuel combustion-process appears to tie up 85% to 95% of the available fuel-sulfur as SO_2; 1% to 3% as SO_3; and less than 5% in the ash.

GASEOUS EMISSIONS FROM LARGE UNITS

	NO_x	SO_2	SO_3	
	(ppm)	(%)*	(%)*	(ppm)
Extreme Range	0 - 1,020	12 - 100	0.3 - 11.5	0 - 76
Normal Range	300 - 700	85 - 100	0.3 - 2.8	6 - 24
Most Common Values	460 - 480	98 - 100	1.0 - 1.3	14 - 22

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*Values expressed as % yield of total sulfur in the fuel.

To a varying extent, the gaseous SO_3 is adsorbed on or reacted with the ash, slag, and interior surfaces of the furnace, shifting the sulfur balance slightly.

Catalytic substances, such as iron oxides and vanadium- and iron-bearing ash-deposits, are often present and accelerate SO_3-formation. Magnesium additives have been shown to be particularly effective in inhibiting these catalytic effects. High SO_3 levels result in plume opacity, even when particulate loadings are low. This problem is often encountered with oil-fired boilers.

Even very low SO_3 concentrations can be deleterious, because dew-point considerations preclude operating temperatures of less than 250 to 260°F, below which serious corrosion problems and acidic smut formation result.

TABLE B-11

SUMMARY OF GASEOUS POLLUTANTS (PPM, DRY BASIS) FROM COAL-FIRED POWER PLANTS

Plant	Oxides of Nitrogen[1]		Sulfur Dioxide		Sulfur Trioxide		SO_3/SO_2		Carbon Monoxide		Hydro-Carbons[2]		Formal-dehyde	
	a	b	a	b	a	b	a	b	a	b	a	b	a	b
1	232	664	2420	1370	4	2	0.0017	0.0015	0	0	25	7	0.30	0.25
2	406	335	1330	1820	1	19	0.0008	0.0104	6	4	14	6	0.16	0.061
3	398	520	2080	2350	25	16	0.0120	0.0057	7	10	16	2	0.077	0.056
4	520	334	1850	1320	4	3	0.0022	0.0023	7	8	12	8	0.045	0.054
5	593	521	830	1110	5	22	0.0060	0.0198	17	5	6	8	0.11	0.066
Avg	430	475	1702	1594	8	12	0.0045	0.0079	7	5	15	6	0.138	0.097

1) Measured as NO_2

2) Expressed as CH_4

a = Fly-ash collector input gas

b = Fly-ash collector output gas

b. Nitrogen Oxides

Within this group are included four common forms: NO, NO_2, N_2O_4, and N_2O_5. The last two are unimportant in the present context; N_2O_4 dissociates readily into NO_2 at the temperature of interest, and N_2O_5 is thermally unstable. In the dynamics of the fossil fuel combustion process, little oxygen is available for the initial formation of NO. If the available oxygen is increased by increasing excess air, NO formation is promoted, unless combustion temperatures are reduced. Higher temperatures result in increasingly higher NO equilibrium concentrations.

Further oxidation of NO to NO_2 is favored at temperatures below 450°F (Ref. B-90). The reaction is so slow, however, that practical furnace configurations do not allow sufficient residence time for this reaction to occur. Thus, NO_x stack discharge compositions are comprised largely of NO (Ref. B-91).

Figures B-54 and -55 show data summarized in References B-92 and B-90, respectively, on NO_x emissions from fossil fuel fired sources of various sizes.

c. Hydrocarbons

Hydrocarbon emissions are comprised of many organic compounds: lower molecular weight aliphatics, unsaturates, aromatics, and oxygenated and halogenated compounds. The species which are most difficult to oxidize, such as the aromatics, comprise a substantial fraction of the overall hydrocarbon emissions. Polynuclear hydrocarbons, notably benzpyrenes, have received considerable attention due to their carcinogenic properties. The low oxidation propensity of benzpyrene and other aromatics results in the formation of soot during combustion, despite high excess air levels.

Unburned hydrocarbon emissions are the inevitable result of inefficient combustion. True hydrocarbons are released during intermediate stages of non-ideal combustion. Oxygenated or otherwise transformed species, such as formaldehyde, are formed following this initial cracking. True and transformed hydrocarbon emission values have been published (Refs. B-81, -88, and -92) as previously shown in Table B-11. Values of benzpyrene emissions have been reported (Ref. B-93) as a fraction of particulates from oil firing.

d. Carbon Monoxide

This compound is a fuel itself, having an approximate heating value of 4500 Btu/lb. Low excess air levels or poor combustion-air distribution result in a deficiency of oxygen for the complete combustion of carbon. The CO formed can thus escape from the system

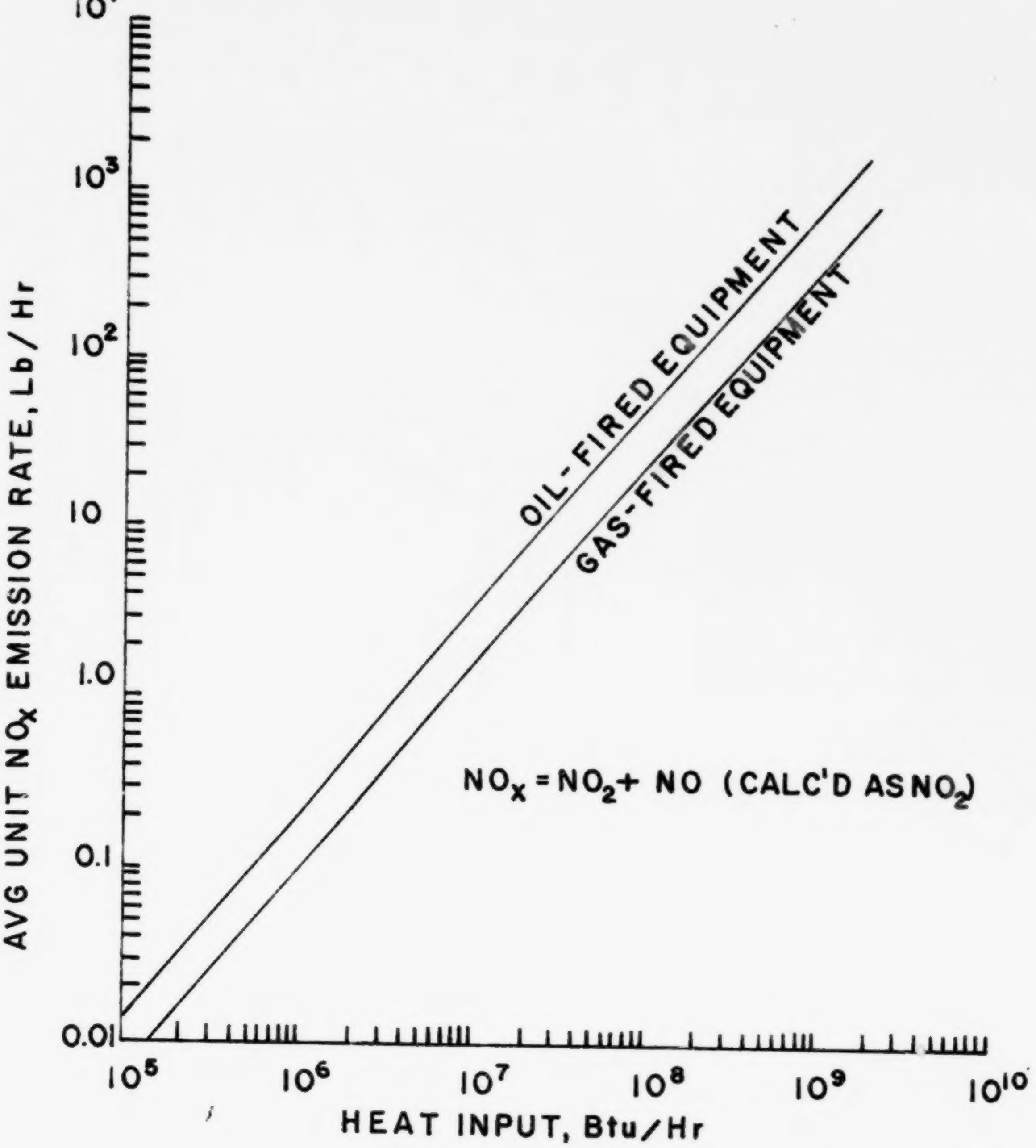


FIGURE B-54. ESTIMATION OF AVERAGE UNIT NO_X EMISSIONS FROM SIMILAR PIECES OF COMBUSTION EQUIPMENT

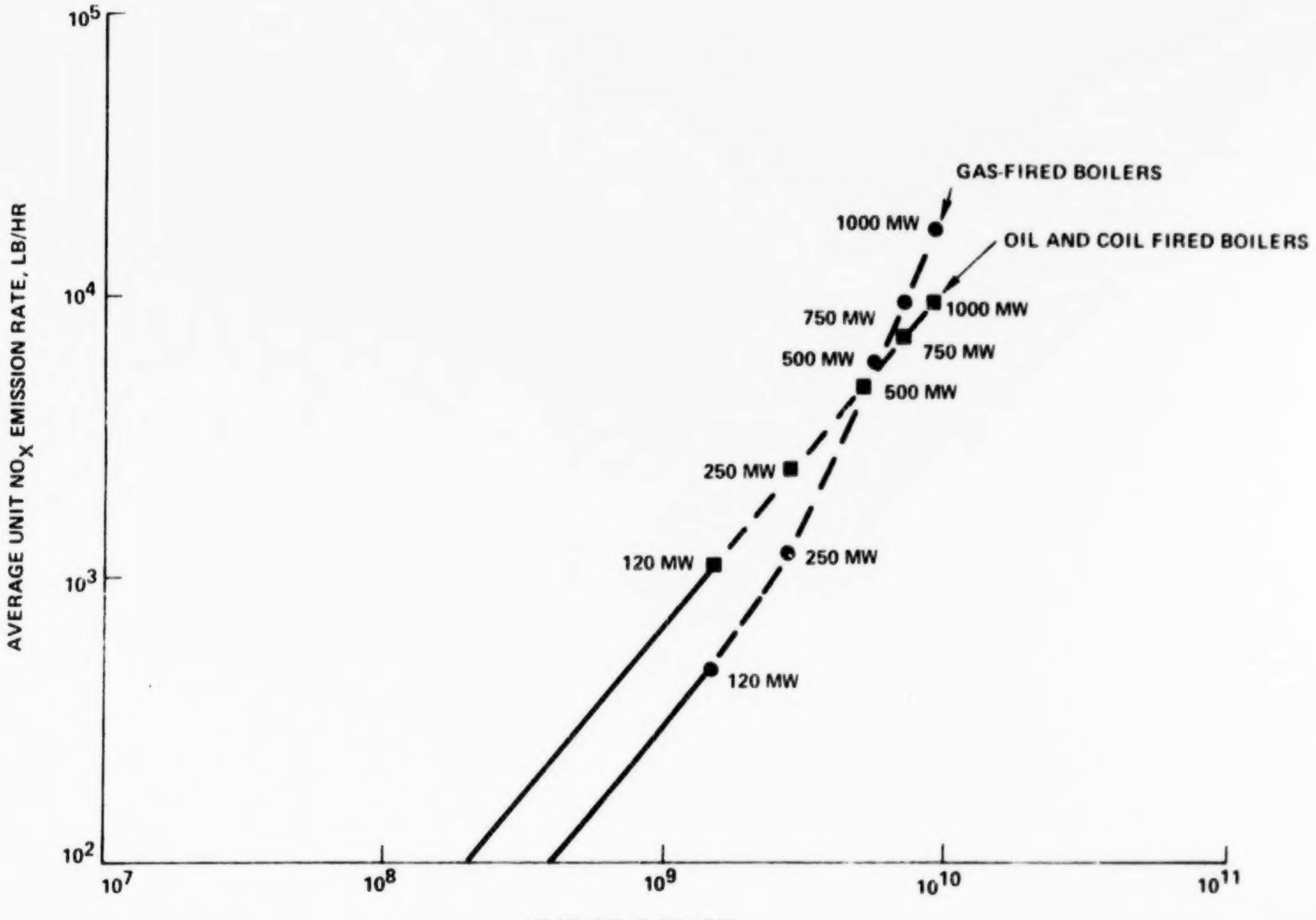


FIGURE B-55. ESTIMATION OF AVERAGE UNIT NO_X EMISSIONS FROM LARGER SIZED COMBUSTION SYSTEMS without undergoing the (normal) further conversion to CO_2. Values of CO emissions have been reported (Refs. B-88 and -89) for a variety of sizes of fossil-fuel combustion sources and are included in Table B-11 above.

e. Gaseous Emissions Summary

Natural gas combustion does involve an NO_x emission problem. However, no particulates or SO_x, and only negligible hydrocarbons, are associated with this type of firing. Fuel oil combustion also produces NO_x emissions, but with only traces of particulates being formed. Sulfur-bearing oils release over 90% of their sulfur as noxious SO_2; only small amounts of SO_3 are generated. The SO_3 levels will increase appreciably when firing vanadium bearing oils, such as Venezuelan, in which the vanadium acts as a catalyst during combustion. Higher SO_3 concentrations result in smut formation, as well as plume opacity. Coal combustion also results in the generation of NO_x, as well as SO_2, and traces of SO_3. The last is normally in low enough concentration to preclude smut formations. The predominant pollutant from coal combustion is particulates.

B. EMISSION CONTROL TECHNIQUES

1. Particulate-Emission Control Devices

There are four basic, or generic, types of particulate collection devices:

- Mechanical Collectors
- Wet Scrubbers
- Fabric Filters
- Electrostatic Precipitators

a. Mechanical Collectors

These devices exploit centrifugal forces to separate particulates from gas streams. The gas is either vaned, or introduced tangentially, into a tubular element. The resulting tangential velocity causes the particulates to centrifuge from the gas stream. On large units, tubular elements are often arranged in multiples of several hundred tubes (multicyclones). One such tube element is shown in Figure B-56.

Being essentially inertial in character, mechanical collectors are selective with respect to particle size and density. Multicyclones are often used to fractionate and reinject coarser, higher carbon-content ash.

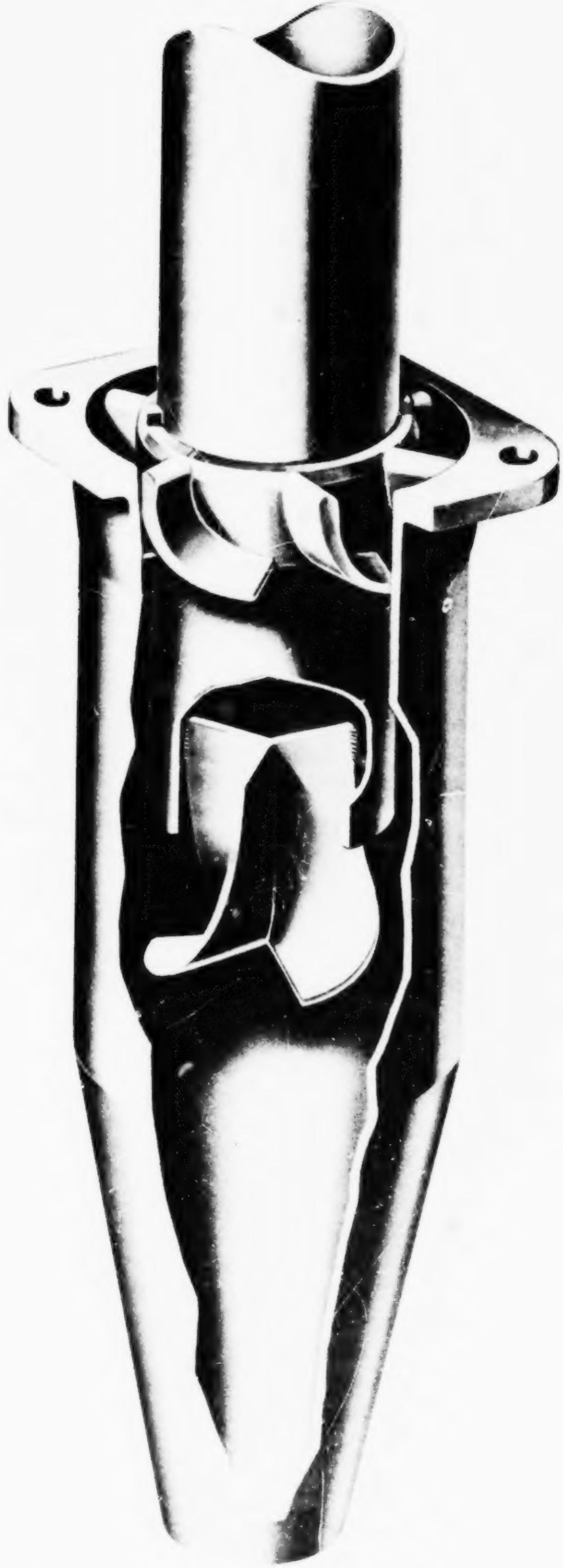


FIGURE B-56. MULTI-CYCLONE TUBE ELEMENT

Decreasing tube diameters or increasing the particulate size and density results in greater collection efficiency. Because of practical considerations, such as ash-pluggage and ease of fabrication, 9 or 10 in. (I.D.) tube is shown in Figure B-57. As is evident, moderate pressure drops of 2 to 3 in. W.C. are not uncommon.

With a 2 to 3 in. W.C. pressure drop, a mechanical collector can be expected to exhibit 75 to 80% collection efficiencies on suspension-fired (pulverized coal) units. The relatively low performance and relatively high power input of mechanical collectors are their principal disadvantages. Their main advantage is their low installed cost, which is on the order of \$0.15 to \$0.25 per ACFM of gas.

b. Wet Scrubbers

These devices cause droplets of scrubber liquid to impinge with the particulates entrained in the flue gas. The size and weight of the particulate is effectively increased by wetting, so that they can then be collected by mechanical (inertial) separation. Scrubber performance depends on collisions between scrubber liquid droplets and particulates; these collisions can be increased in three ways:

- Increasing turbulence
- Decreasing liquor droplet-size by atomization
- Increasing amount of scrubber liquid used

Semrav (Ref. B-94) summarized the power inputs required to accomplish the first two effects. He concluded that scrubber performance is basically a function of power input.

The effects of relative liquor concentration (liquid to gas ratio), although not widely reported, are well known by equipment suppliers. So-called Stefan Flow Effects are largely undefined for situations where condensation or evaporation processes occur.

Daily swings in generator output and boiler operation are common in all but the largest base-loaded units. As a result, variations in gas volumes must be handled. Variable orifice contactors similar to that shown in Figure B-58 are well suited to this type of operation, provided plugging does not occur.

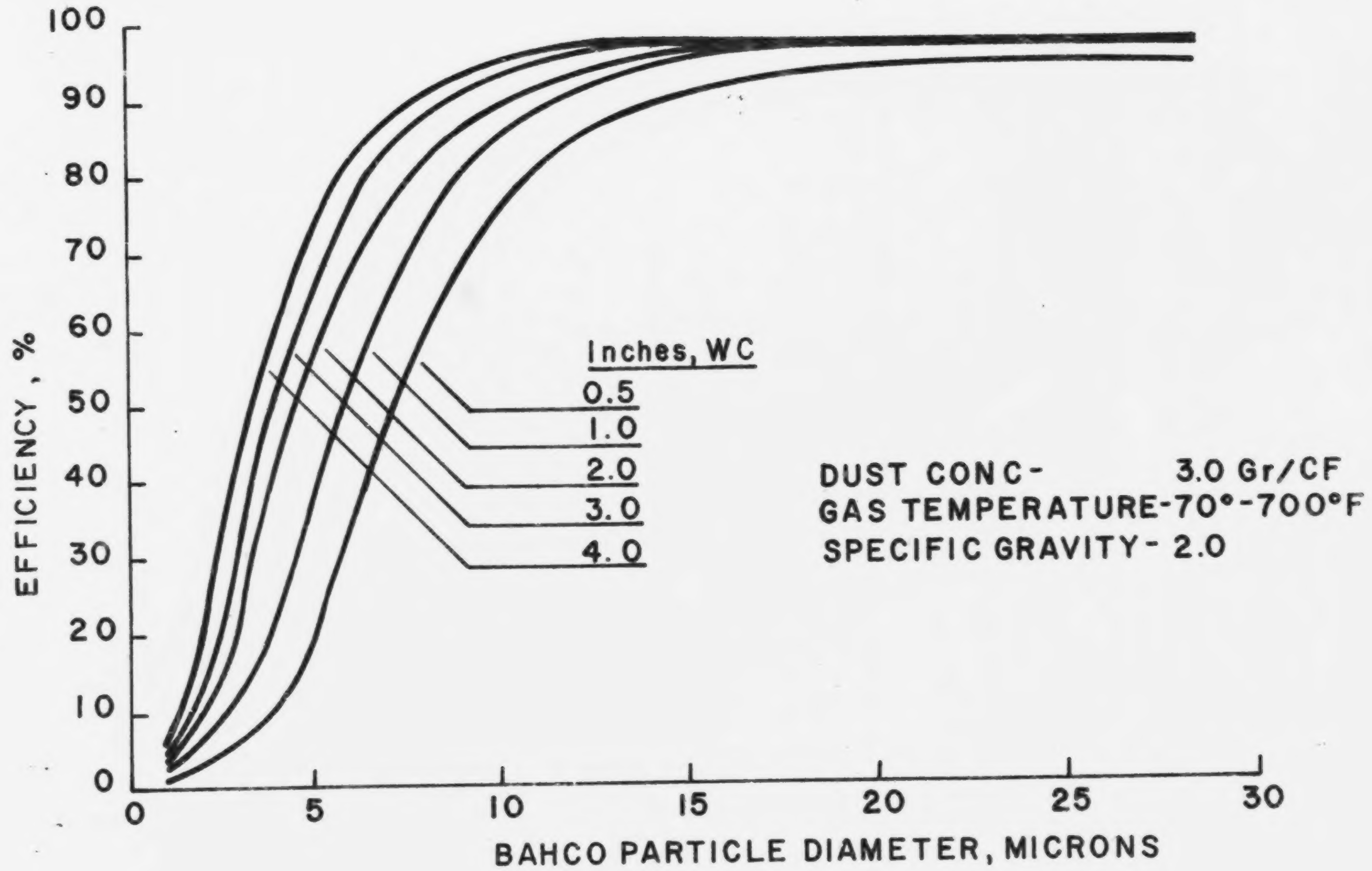


FIGURE B-57. CYCLONE DUST COLLECTOR - EXPECTED MICRON EFFICIENCY

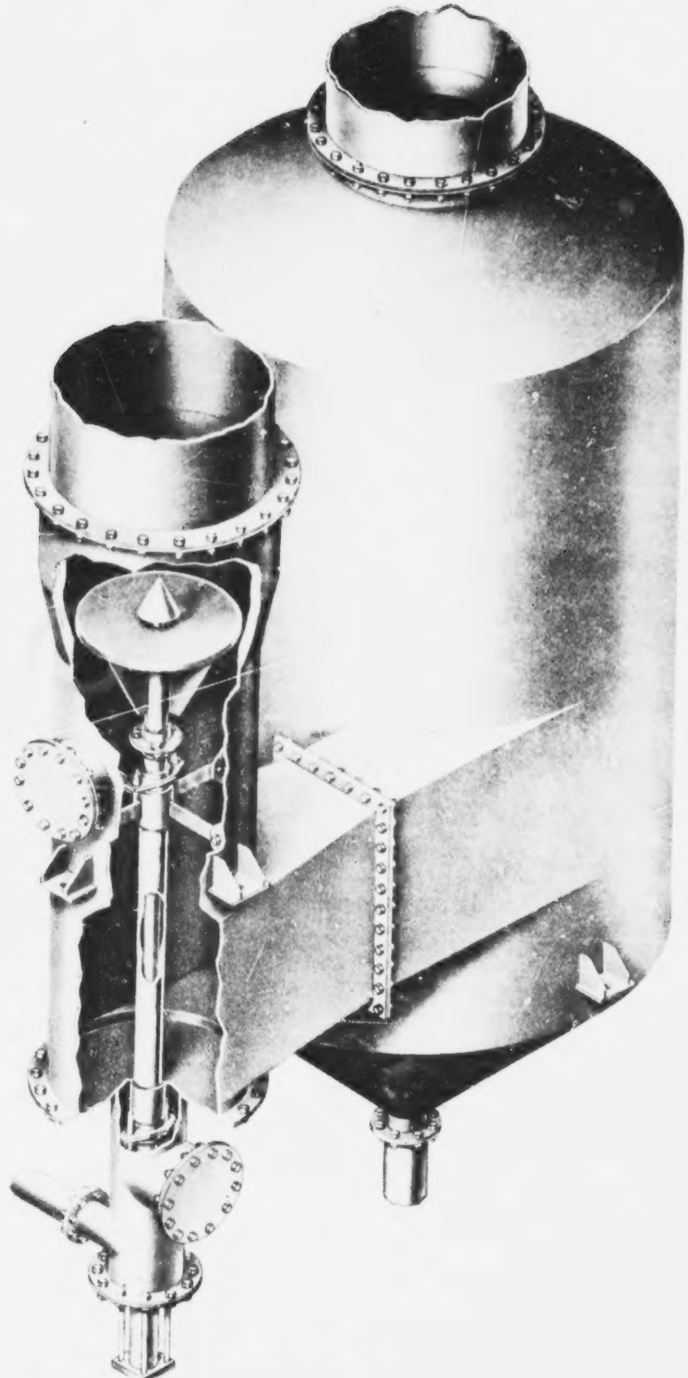


FIGURE B-58. VARIABLE-ORIFICE LIQUID SCRUBBER

Although capable of much better collection efficiency, scrubbers require higher power-inputs than mechanical collectors. Wet scrubber installed-costs for power boilers are sharply increased by the required stainless-steel construction; installed costs of \$0.50 to \$0.60 per ACFM are common. Additional process details, such as consideration of water-availability and wet-ash and effluent-water disposition, must also be made. Although the wet scrubber requires about the same physical space as a mechanical collector, the associated water- and ash-handling equipment can impose an additional space demand of 2 or 3 times that space.

In terms of SO_x and particulate removal, wet scrubbers have shown 99% overall collection-efficiencies at 6-in. W.C. pressure drop on suspension-fired boilers using the dolomite-injection process (Ref. B-95).

c. Fabric Filters

Similar to the operation of a household vacuum cleaner, dust-laden gas is passed through a filter cake of collected ash deposited on the fabric envelope. Fabric filters are capable of 99+% collection efficiencies. While simplicity and good performance make these systems attractive, space requirements and pressure drop, typically 5-in. W.C., are serious disadvantages. Periodic filter media replacement is also required, which adds significantly to operating costs. A multitubular bag house is shown in Figure B-59.

Installed costs for fabric filters are typically \$1.00 to \$1.25 per ACFM, and space requirements are two to three times that for inertial collectors.

d. Electrostatic Precipitators

These devices employ high intensity electrical fields to separate particulates electrostatically from the flue gas. Although relatively insensitive to particle size variations, precipitators depend on particle resistivities that are consistent with effective operation. White (Ref. B-84) has indicated that fly ash resistivities below 10^{12} ohm-cm are considered good for electrostatic precipitation. This is shown in Figure B-60.

Single-stage electrostatic precipitators, as shown in Figure B-61, will remove up to 99.5% of entrained fly ash. Space requirements are similar to those for fabric filter, as are installed costs. Operating costs, however, are significantly lower, owing to the fact that less than 0.5-in. W.C. pressure drop is typical. Precipitator size and installed cost are sharply influenced by the bulk resistivity of the fly ash. The precipitation rate or migration velocity (w), shown in Figure B-60, is an overall performance factor which is observed in establishing the required collecting plate area, and thus the overall size and cost of the precipitator. The relationship is given in the Deutsch (Ref. B-96) equation:

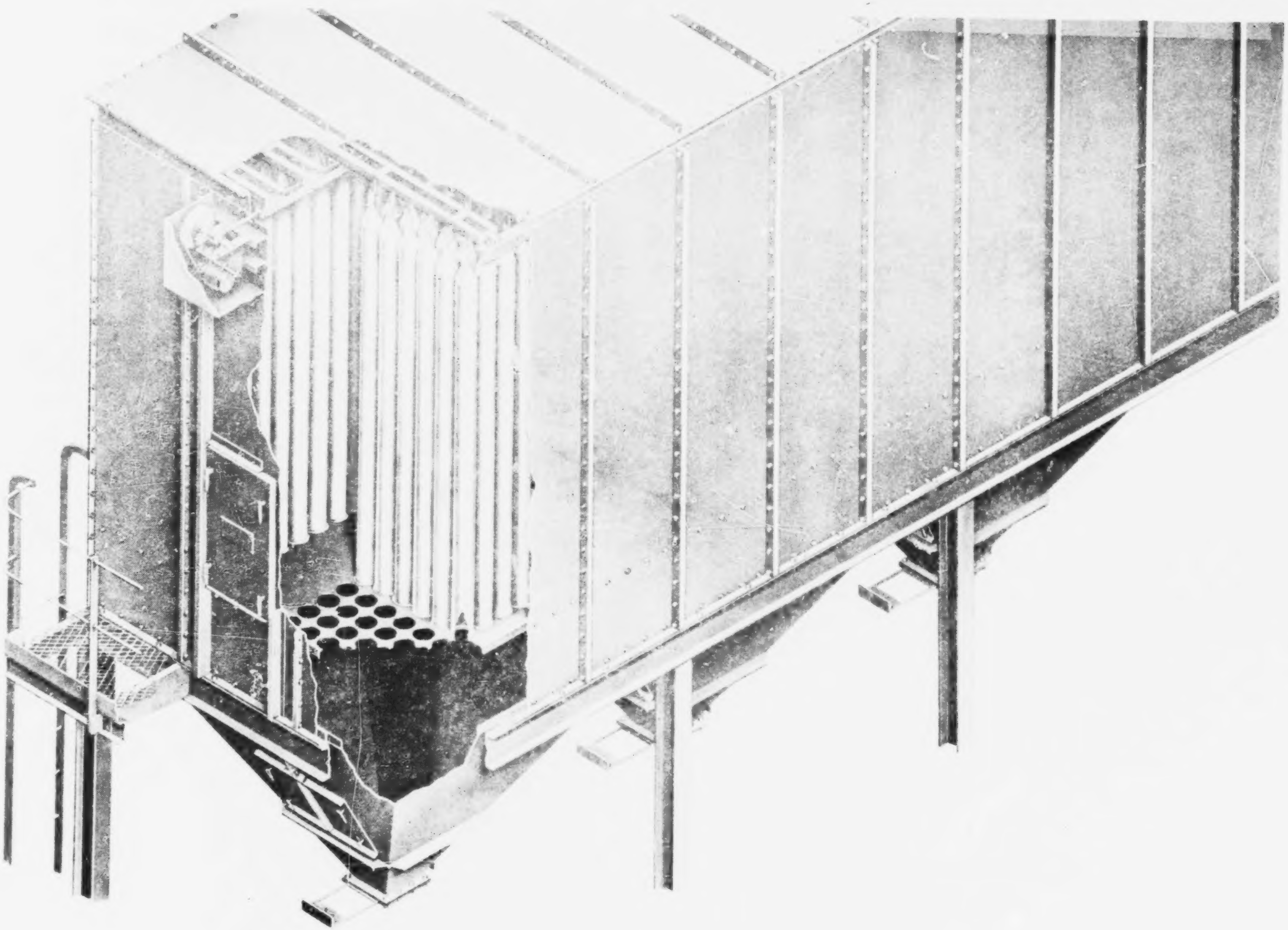


FIGURE B-59. MULTI-ELEMENT BAG HOUSE

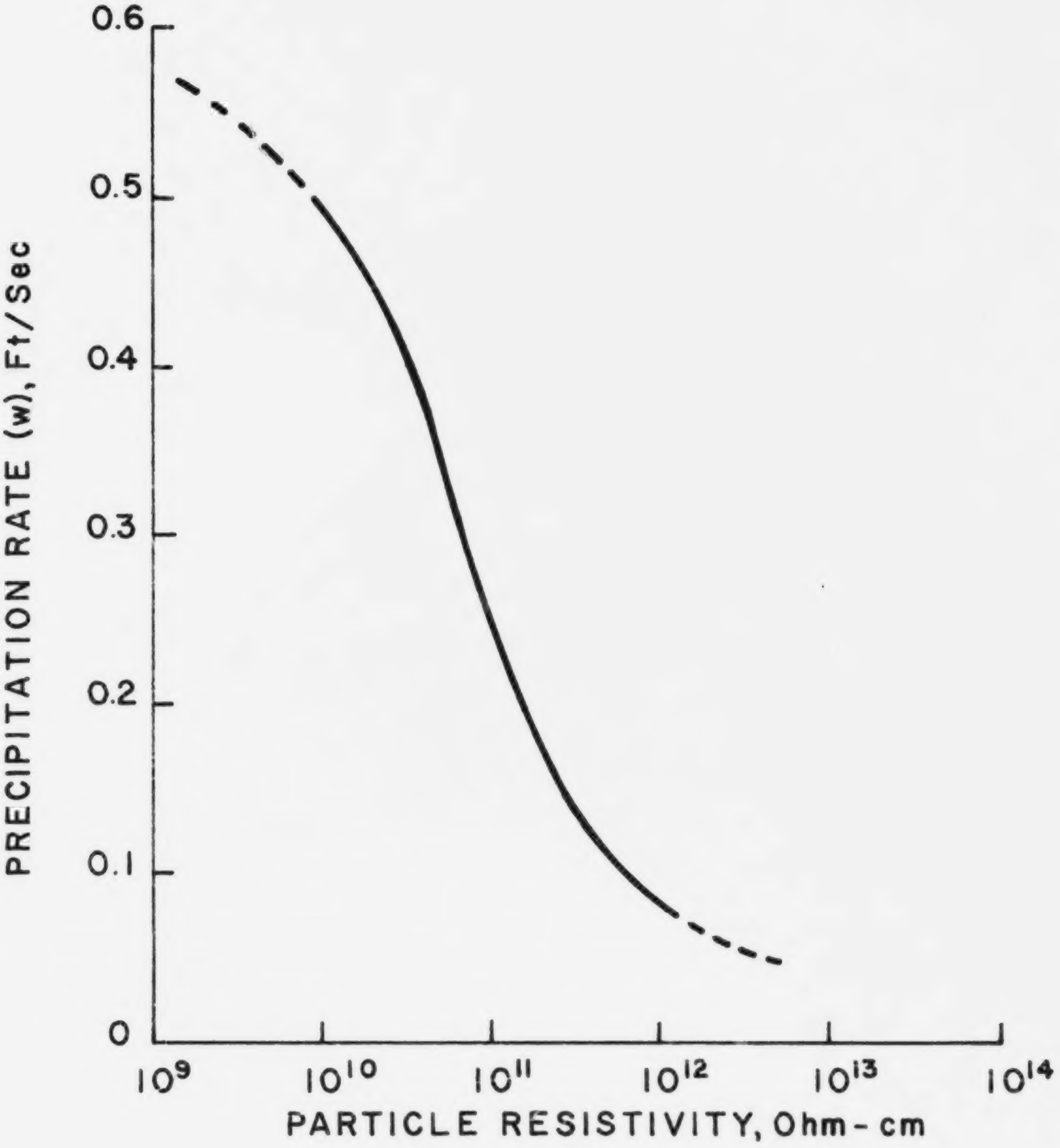


FIGURE B-60. PRECIPITATION RATE VS FLY ASH RESISTIVITY - FIELD DATA

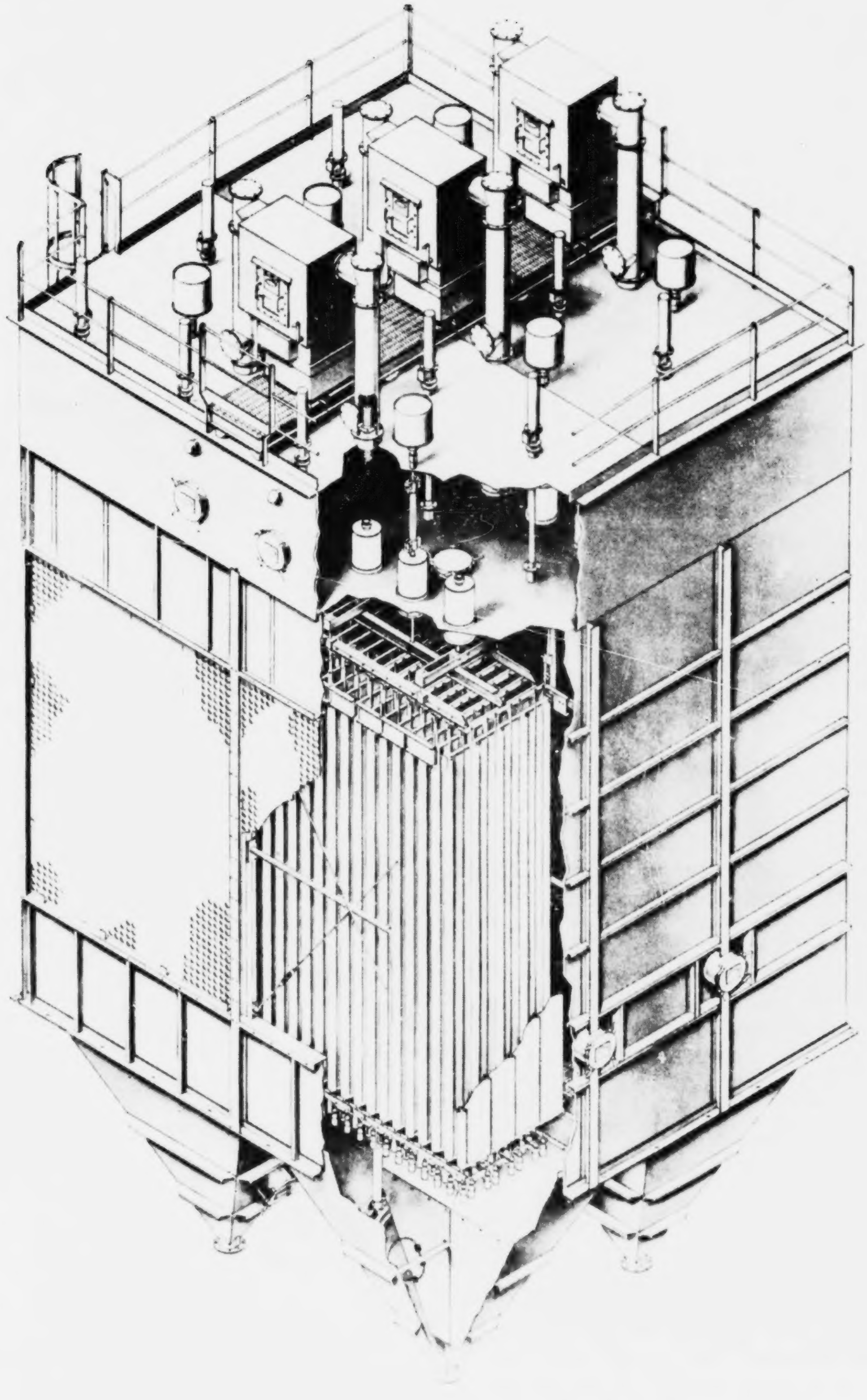


FIGURE B-61. SINGLE-STAGE ELECTROSTATIC PRECIPITATOR

$$N = 1 - e^{-\frac{Aw}{V}}$$

where: N = collection efficiency

A = collecting plate area (ft^2)

w = precipitation rate (ft/sec)

V = gas-flow rate (ft^3/sec)

Electrostatic precipitator installed costs are given in Figure B-62 for several typical operating conditions.

2. Gaseous-Emissions Control Devices

a. Sulfur Oxides Control

Three basic modes of control of this pollutant-class are possible:

- Fuel desulfurization
- Flue-gas desulfurization
- Dispersion

Obviously, the last is not a true control technique, for it is only effective in reducing local ground-level concentrations. Although the upper atmosphere has the fortunate capability of transforming or dissociating many compounds, this capability must be regarded as finite. Consequently, dispersion is normally considered as only a stop-gap control technique.

The U.S. Bureau of Mines has been very active in studying both fuel and flue-gas desulfurization systems. To date, however, fuel desulfurization is still very expensive. A typical economic penalty for producing low-sulfur fuel (Ref. B-97) is $\$0.10/10^6$ Btu.

The state of the art in flue-gas desulfurization has advanced rapidly over the past decade, primarily due to a thrust of activity by the EPA and the Bureau of Mines.

While dozens of processes are being considered and are perhaps technically feasible, only four are now at second generation, or commercial stages, of development (Refs. B-98 and -99). These are:

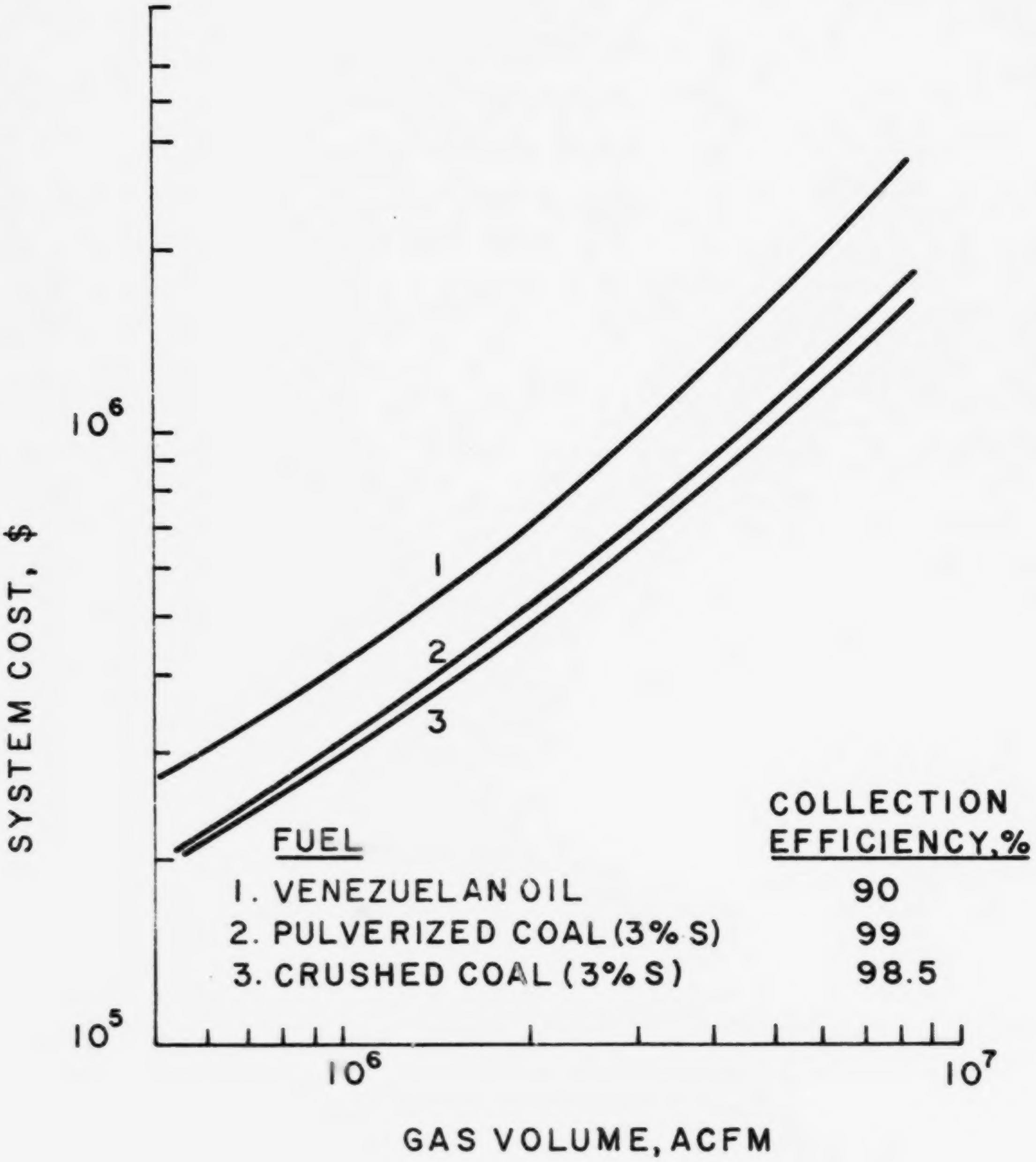


FIGURE B-62. ELECTROSTATIC PRECIPITATOR INSTALLED COSTS VS GAS THROUGHPUT

- Reinluft (Reinluft/Gmbh)
- Catalytic Oxidation (Monsanto)
- Alkalized Alumina (BuMines)
- Reactive-Stone Injection (EPA/Comb. Engrg.)

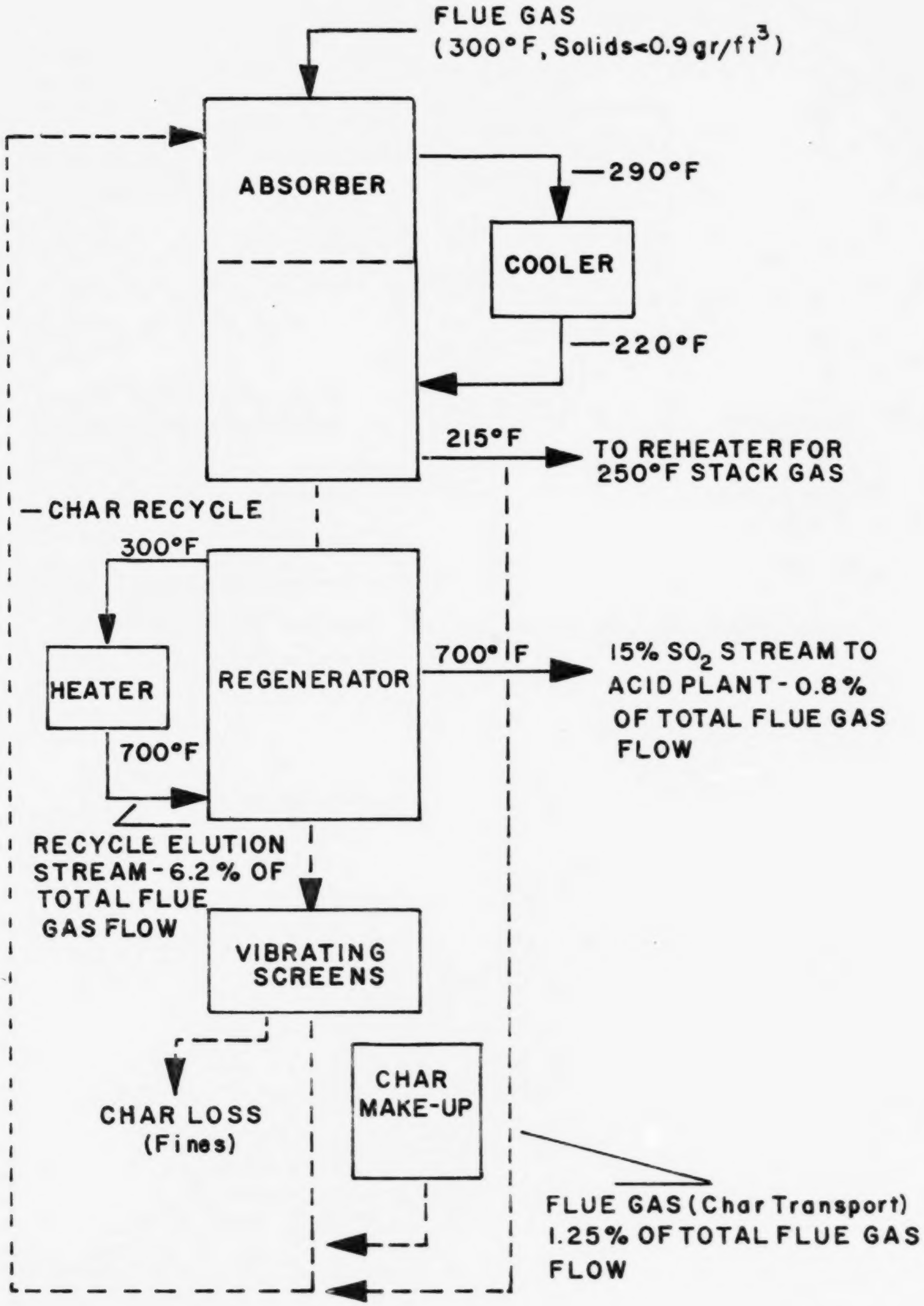
Figures B-63 through -66 diagram these processes. The first three involve somewhat complex chemical-process hardware, while the reactive-stone (dolomite) injection process is more straightforward. Perhaps because of this, the dolomite injection process has been advanced to the point closest to practical application (Refs. B-86, -98, and -99). Although commercial versions of the dolomite injection process are based on wet-scrubbing systems following the air-preheater, the EPA is investigating the use of dry-dust collection (Ref. B-86). In tests on a dry fabric-filter, Southern California Edison Co. and Air Preheater Co. have reported that further SO_x reductions are realized by passing the flue gases through the bag filter-cake.

As mentioned earlier, reduction of the flue-gas sulfur oxide levels will have a detrimental effect on electrostatic precipitator performance. This is an important consideration in pursuing dry flue-gas desulfurization processes. R&D activities for optimizing the precipitation process, as applied to dolomite-injected power boilers, is now under way with EPA sponsorship (Ref. B-95).

b. Nitrogen Oxides Control

As discussed earlier, NO_x formation is favored by high available excess air and high flame-temperatures. As such, present attempts to limit NO_x emissions from power boilers have been centered on burner and combustor design and control thereof. Until very recently, there had been relatively little activity aimed at eliminating NO_x from flue gases by sorption or conversion. NO_x elimination has largely been sought in terms of prevention rather than removal, although data have been reported (Ref. B-100) correlating NO_x emission with gas recirculation processes and the overall aspects of the problem (Ref. B-90).

As with CO and the hydrocarbons, the problem of NO_x emissions from large steam generators is not considered to be as acute as is the SO_x problem. The general consensus of air pollution control technologists appears to be that NO_x control will be more actively pursued after the development of viable solutions for the SO_x problem.



FLUE GAS
(300°F, Solids<0.9 gr/ft^3)
ABSORBER
290°F
COOLER
220°F
215°F
TO REHEATER FOR 250°F STACK GAS
CHAR RECYCLE
300°F
HEATER
REGENERATOR
700°F
700°F
15% SO_2 STREAM TO ACID PLANT - 0.8% OF TOTAL FLUE GAS FLOW
RECYCLE ELUTION STREAM - 6.2% OF TOTAL FLUE GAS FLOW
VIBRATING SCREENS
CHAR LOSS (Fines)
CHAR MAKE-UP
FLUE GAS (Char Transport) 1.25% OF TOTAL FLUE GAS FLOW

FIGURE B-63. FLOW DIAGRAM - REINLUFT PROCESS

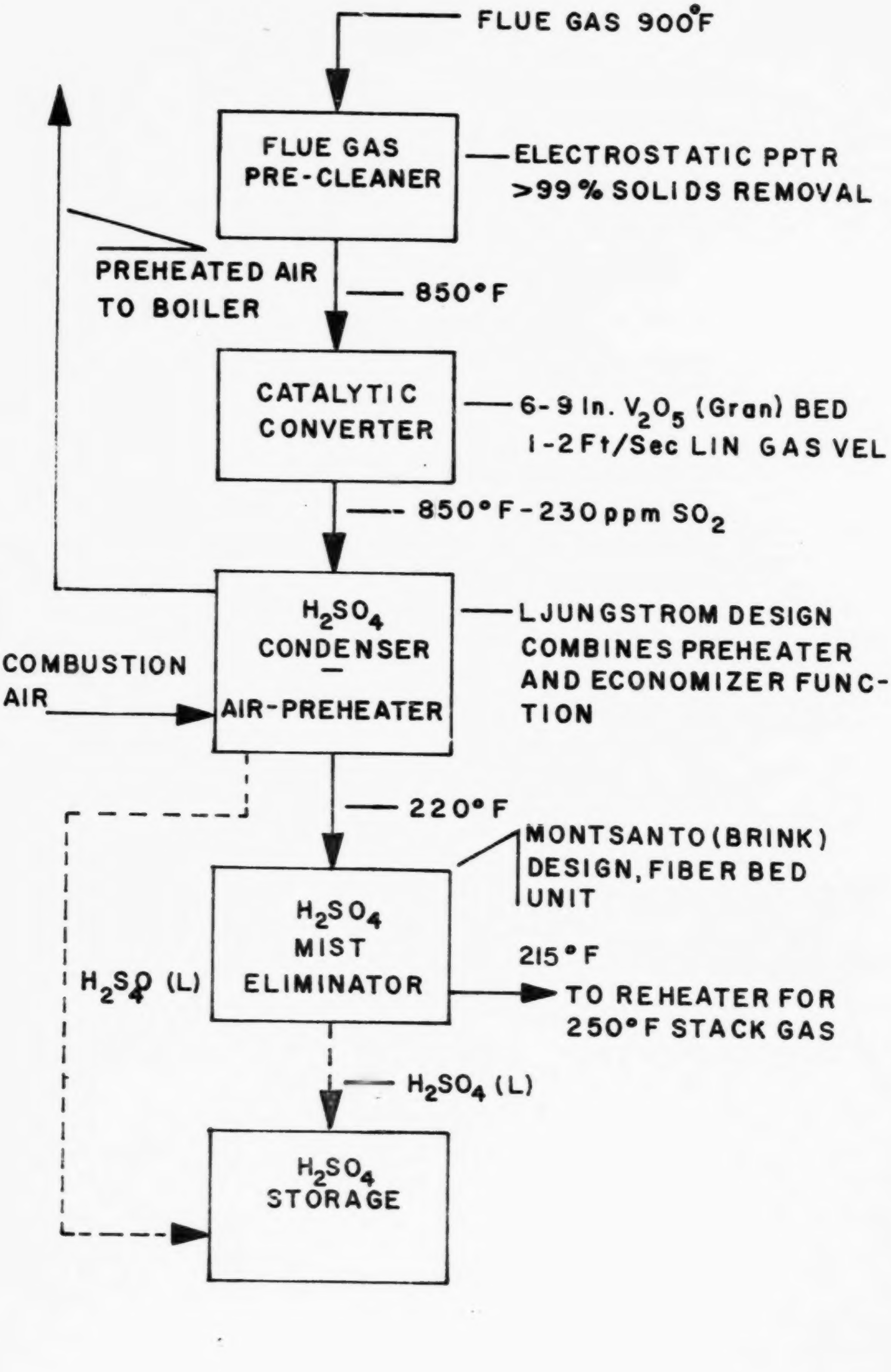

FLUE GAS 900°F
FLUE GAS PRE-CLEANER
ELECTROSTATIC PPTR >99% SOLIDS REMOVAL
PREHEATED AIR TO BOILER
850°F
CATALYTIC CONVERTER
6-9 In. V2O5 (Gran) BED 1-2Ft/Sec LIN GAS VEL
850°F-230 ppm SO2
H2SO4 CONDENSER — AIR-PREHEATER
LJUNGSTROM DESIGN COMBINES PREHEATER AND ECONOMIZER FUNCTION
COMBUSTION AIR
220°F
MONTSANTO (BRINK) DESIGN, FIBER BED UNIT
H2SO4 MIST ELIMINATOR
215°F
TO REHEATER FOR 250°F STACK GAS
H2SO4 (L)
H2SO4 (L)
H2SO4 STORAGE

FIGURE B-64. FLOW DIAGRAM - CATALYTIC OXIDATION PROCESS

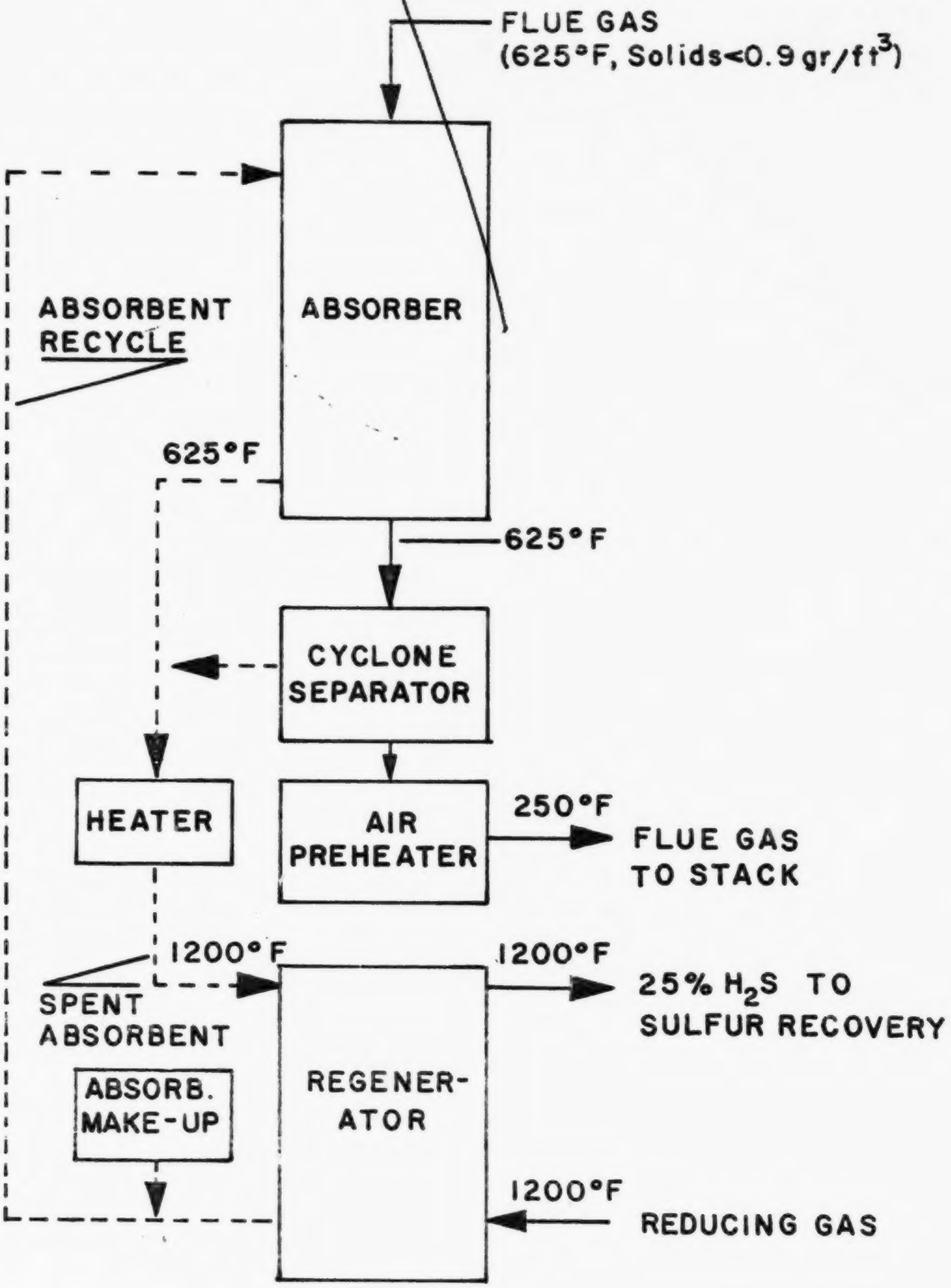

FLUE GAS
(625°F, Solids<0.9 gr/ft³)
ABSORBENT
RECYCLE
ABSORBER
625°F
625°F
CYCLONE
SEPARATOR
HEATER
AIR
PREHEATER
250°F
FLUE GAS
TO STACK
1200°F
1200°F
25% H₂S TO
SULFUR RECOVERY
SPENT
ABSORBENT
ABSORB.
MAKE-UP
REGENER-
ATOR
1200°F
REDUCING GAS

FIGURE B-65. FLOW DIAGRAM - ALKALIZED ALUMINA PROCESS

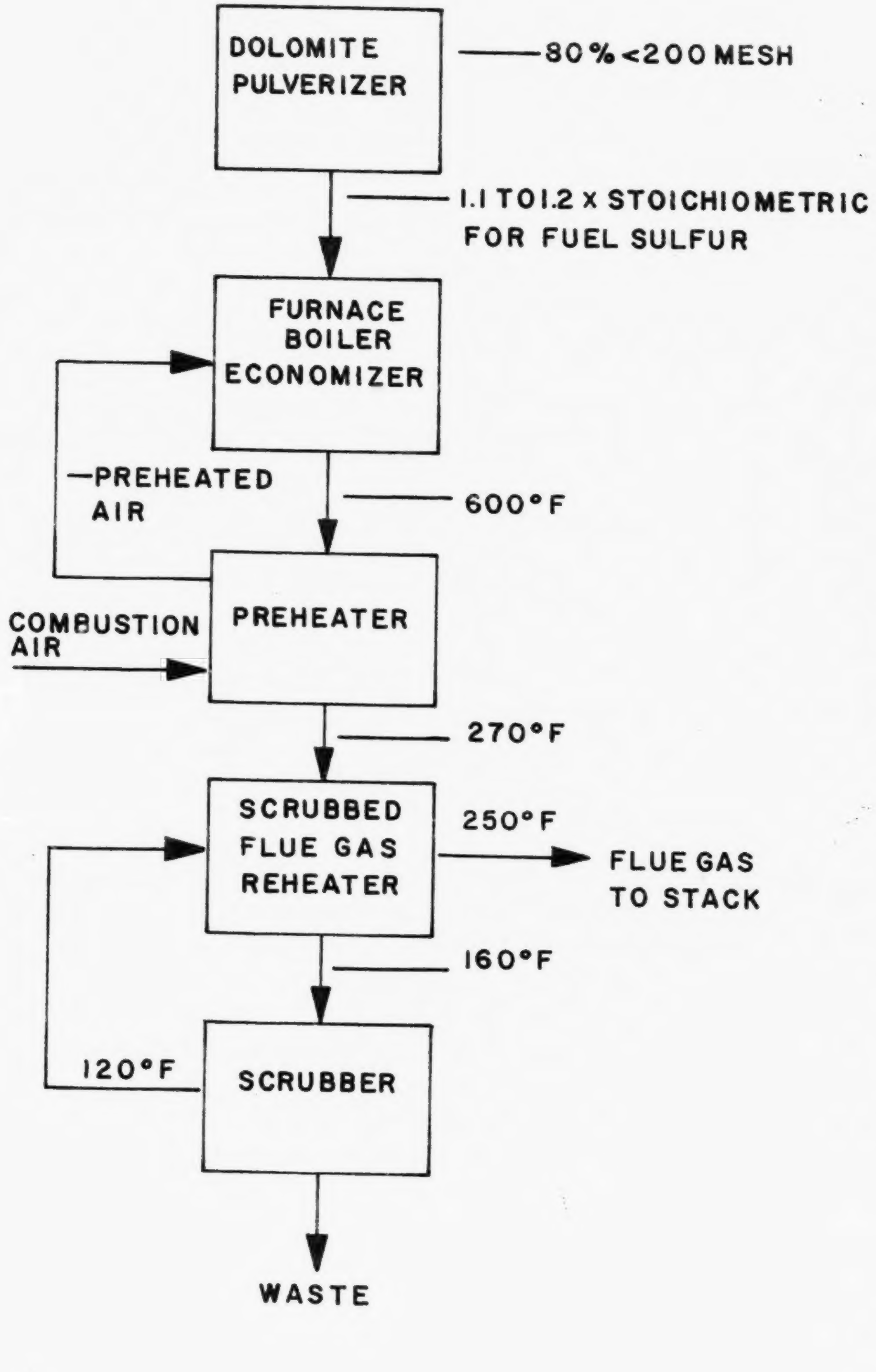

DOLOMITE PULVERIZER
80% <200 MESH
1.1 TO 1.2 x STOICHIOMETRIC FOR FUEL SULFUR
FURNACE BOILER ECONOMIZER
PREHEATED AIR
600°F
PREHEATER
COMBUSTION AIR
270°F
SCRUBBED FLUE GAS REHEATER
250°F
FLUE GAS TO STACK
160°F
120°F
SCRUBBER
WASTE

FIGURE B-66. FLOW DIAGRAM - DOLOMITE/LIMESTONE INJECTION

3. Forecast of Air Quality Standards

The evolution over the next thirty years of air pollution control capability will depend greatly upon the extent which technological momentum maintains pace with requirements. The nature and timing of future air pollution control legislation will very much depend upon the implementation of present-generation legislation. If the technology required to fulfill the presently evolving air quality standards is successfully developed over the next decade, new legislation should then be expected. If implementation is not technically feasible, legislators must mark time until the technology does catch up with existing legislation. Based on the complexity of the problem and the broadness of its scope, it appears that the necessary technological advances will take place only if very large federal funds are expended.

Using a modified Delphi approach (Ref. B-101) to interviewing and then proceeding to: (1) the postulation of possible situations; (2) the development of a preliminary relevance tree; and (3) estimating what the extrapolation of past and present pollution emission levels will produce, forecasts of air quality standards for the year 2000 were projected. Based on this approach, it has been concluded that the most probable situation is one wherein, initially, the air quality criteria recommended in Government documents (Refs. B-102 and -103) will be adopted in the six large metropolitan areas under study (see Section II, A of Volume I). For SO_2, this will require a concentration range of 0.02 to 0.03 ppm annual-mean, and a 24 hour average maximum allowable level below 0.11 ppm. For suspended particulates a maximum concentration in the range of 60 to 80 $\mu g/m^3$ annual-mean level will be observed. It is forseen that these standards will be adopted over the next year or two but that implementation to achieve the sought-for air quality will require more than a decade.

About the year 1985, it is anticipated that a second generation of air quality standards will evolve. For suspended particulates, a level of around 30 $\mu g/m^3$ maximum annual-mean will be called for and some specific components may be pinpointed for essentially complete removal. For SO_2 it is anticipated that the hourly and daily levels will be made much more stringent while the annual level will receive less attention. Standards will call for 24 hour average SO_2-levels to be below 0.03 ppm and annual averages below 0.01 ppm. It will probably not be until around the year 2000 that the levels called for by the "1985 Standards" will be achieved.

About the year 2000, the evolution of another package of air quality standards can be anticipated, but SO_2 and particulates, as such, will not be under major attack at that time. This will be due to the nature of other pollutant priorities that can be foreseen, as well as to the increasing sophistication of ambient monitoring techniques with which to detect source-offenders.

A number of assumptions were employed in arriving at the preceding forecast. One of course is that needed true breakthroughs in the control technology will be made and on time. This assumption also involves a forecast of greatly increased Federal funding for industrial air pollution control research. In arriving at these conclusions regarding air quality standards in the year 2000, it was not anticipated that the character of the six cities would undergo any major revolutions except in the area of mass transportation. It was also assumed that no economic depressions or major wars would occur during the period from 1970 to 2000.

V. EXPERIENCE WITH REFUSE-FIRED STEAM GENERATORS - SELECTED GERMAN PLANTS

A. INTRODUCTION

There are few refuse- or combination-fired steam generators in this country and none, at this writing, which are used in turbo-electric service. For this reason, the present review topic must necessarily be treated by focusing on European or, more specifically, German experience with refuse-fired power plants. To base an assessment of European experience solely on a review of German practice is acceptable, because the latter does epitomize rather well the overall European art. The plants selected assure consideration of the best examples of grate and boiler design, provide examples of different auxiliary-fuel use, and furnish an opportunity to assess SO_x-ash interactions. The plants that have been analyzed in detail include:

- The Munich North Plant, Block I and Block II
- The Düsseldorf plant, one of the four identical units
- Two Stuttgart units

In accordance with standard German practice, the formal contract acceptance tests for each of these plants were performed by the Technischer Überwachungs-Verein (TÜV). The TÜV is a state-sanctioned agency that reviews and approves final design, and performs acceptance tests on virtually all publicly-owned capital facilities. Transcripts of TÜV acceptance test data (Refs. B-104 to -107) on the above plants were procured and reviewed.

B. DESCRIPTION OF GERMAN PLANTS

1. Munich North, Block I

This plant (see Figure B-67)* consists of two identical Benson-type units, both of which are included in this review. These are

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*Drawings of German units are all to the same scale.

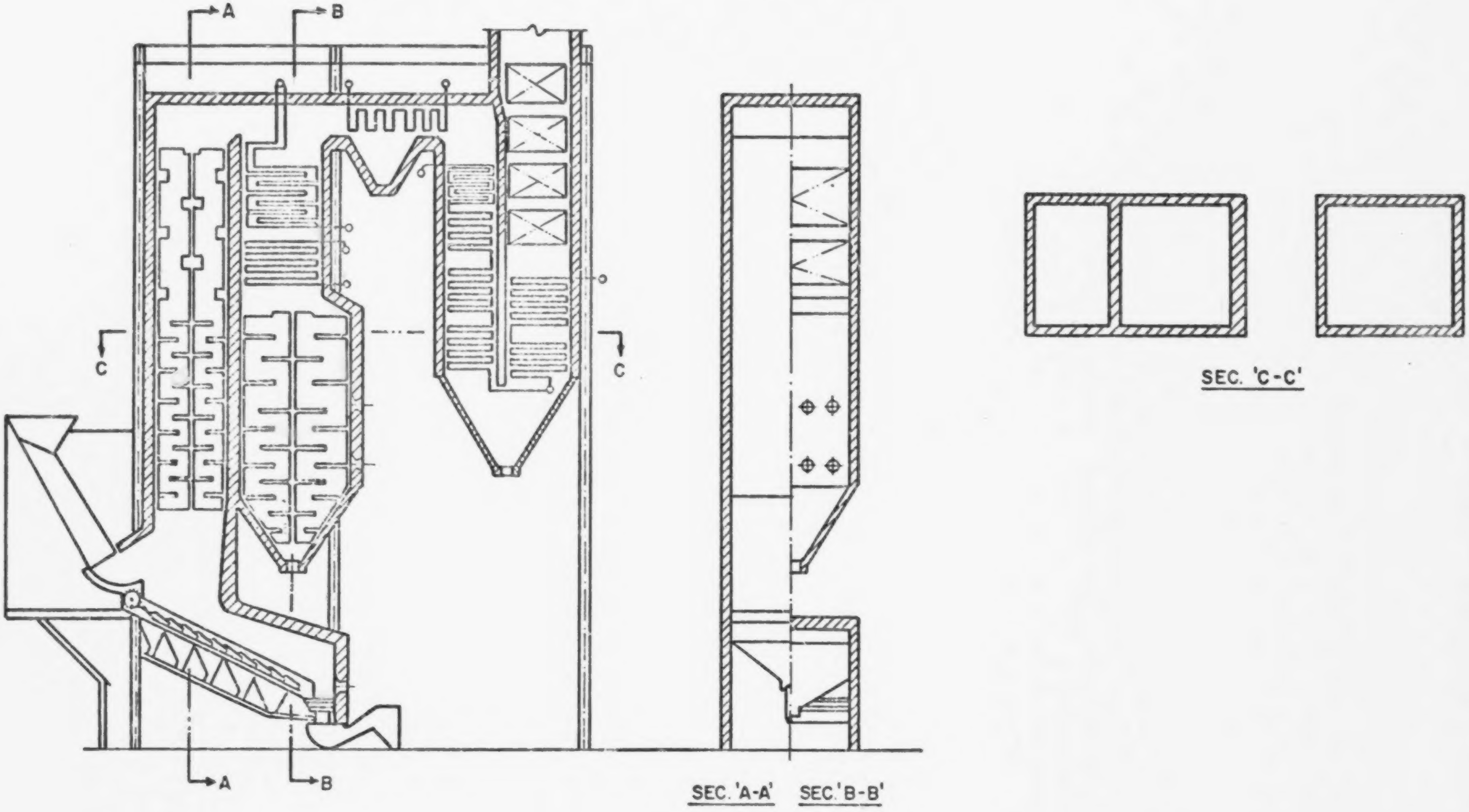
A
B
C
C
A
B
SEC. 'A-A'
SEC.'B-B'
SEC. 'C-C'

FIGURE B-67. MUNICH NORTH COMBINED-FIRED STEAM GENERATOR - BLOCK I the oldest of the units under consideration and are characterized by twin-chamber furnaces; i. e., the refuse and coal-furnace-chambers are separate but share a common tube-wall. The combustion gases are combined at the top of the furnace chambers, and pass through a common superheater and economizer. All of these elements comprise one furnace setting or unit. Each unit includes a Martin (backward reciprocating) grate for municipal refuse combustion and a suspension-fired furnace chamber for the combustion of pulverized-coal. Steam conditions for each Block I unit are 220, 000 lb/hr of 2600 psig steam at 1004/1004°F, while firing 660 tpd refuse plus auxiliary coal. Maximum continuous load is 220, 500 lb/hr of superheated steam at 2, 650 psig and 1004°F. The reheat steam flow at this load is 198, 000 lb/hr at a pressure of 1, 180 psig and 1004°F. Ferrous metals are removed from the combustion water-quenched residue by magnetic equipment.

2. Munich North, Block II

This unit, shown in Figure B-68, is the latest design (1966) under consideration. It was evolved from the Block I units, but with one important design change. The Block II unit is a single-chamber furnace, with pulverized-coal combustion occurring directly above the refuse grate. Steam quality is identical to that of the Block I units; steam production, at 800, 000 lb/hr, is considerably higher.

All the electrostatic precipitators of the Munich North plants are of Lurgi (Frankfurt) design and are horizontal-flow, steel shell precipitators having pyramidal hoppers.

The characteristic differences between the Munich North plants can be seen from the following summarization:

COMPARATIVE INFORMATION ON MUNICH NORTH PLANTS

	Block I	Block II
No. of Turbines	1	1
No. of Steam Generators	2	1
Refuse Heat Input, % (LHV)	40	20
Refuse Rate, tpd	660	1060

3. Düsseldorf

This plant (Figure B-69) consists of four essentially identical boilers, arranged in pairs. The Düsseldorf furnace is primarily for firing refuse, although there are auxiliary oil guns that can be used for start-up and when the heating value of refuse is low. The refuse is fired

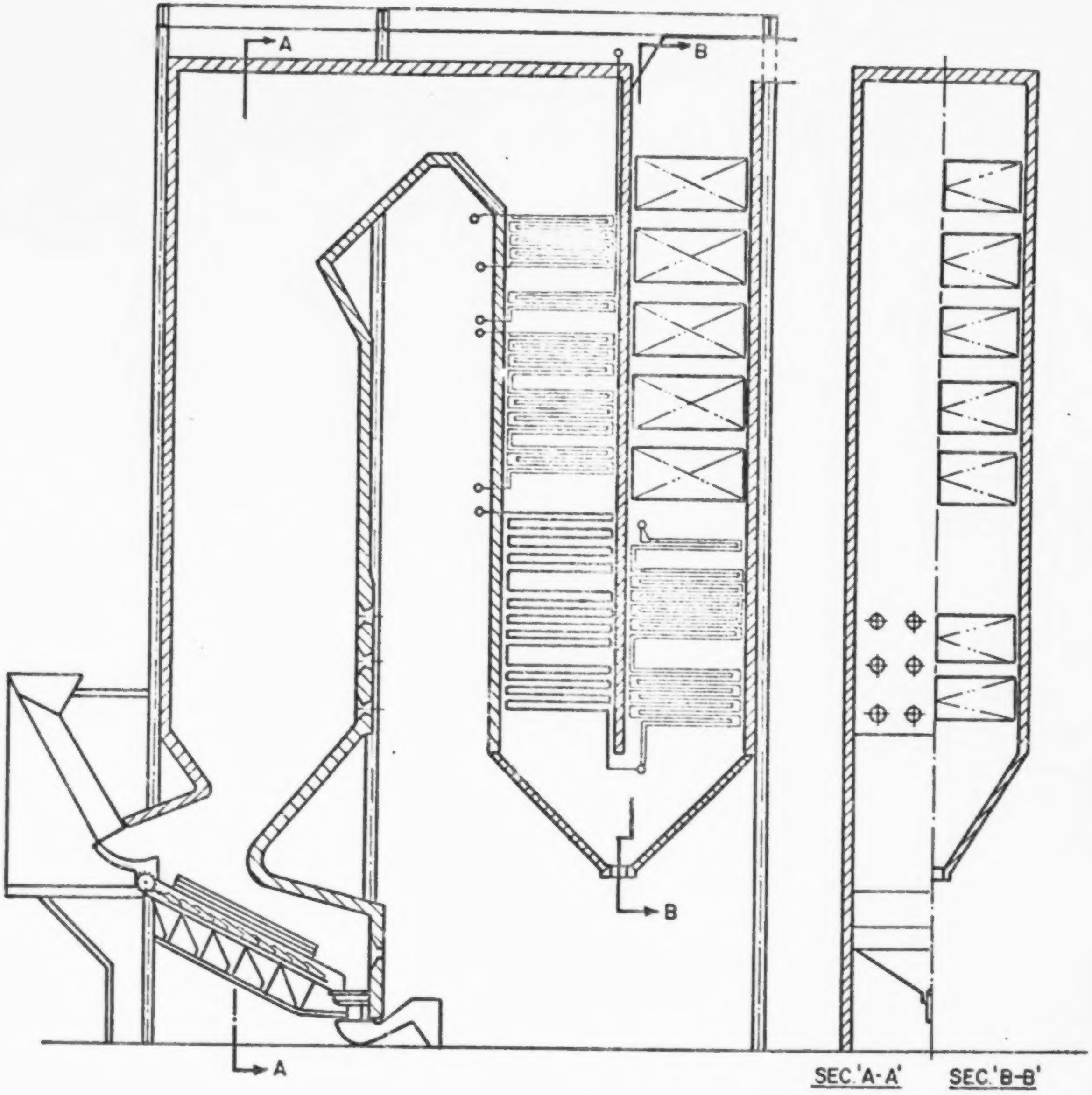
A
A
B
B
SEC.'A-A'
SEC.'B-B'

FIGURE B-68. MUNICH NORTH COMBINED-FIRED STEAM GENERATOR - BLOCK II

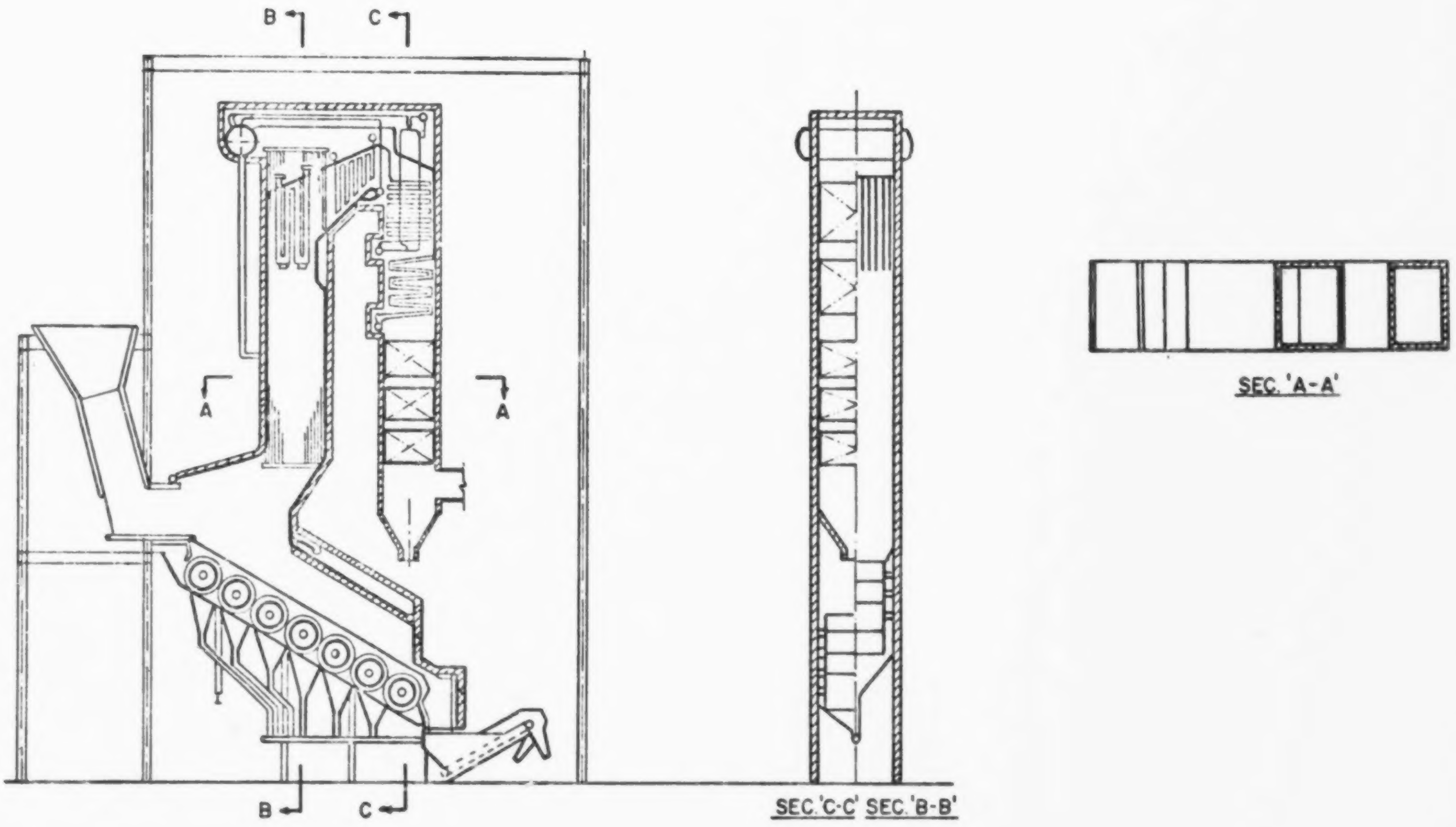
B
C
A
A
B
C
SEC.'C-C'
SEC.'B-B'
SEC.'A-A'

FIGURE B-69. DUSSELDORF REFUSE-FIRED STEAM GENERATOR on a roller grate; as at Stuttgart, only bulky refuse is shredded. The combustion air can be directed over a steam air-preheater and a feedwater/air-preheater if heating of this air is desired. Three electrostatic precipitators treat the combined flue gases of four units. There is also provision for recirculating waste gas.

Each steam generator is designed to deliver from 25,500 lb/hr to 35,200 lb/hr of steam at 1,280 psig and 932°F. The roller grate of VKW design is designed to burn 22,050 lb/hr of refuse with an exit gas temperature of 410°F.

4. Stuttgart

The Stuttgart plant consists of two units, which are nearly identical. Both units have one oil-furnace and one refuse-furnace with the gases combining before entering the convection section. As with the other German units considered, there is provision for recirculation of the flue gases to cool the residue. The units have steam/air and waste-gas/air (panel design) air-heaters. The steam generators are designed to deliver 204,600 lb/hr steam at 925 psig and 977°F for normal operation with either oil-firing or combined-firing. The maximum continuous power level is 275,600 lb/hr steam at the same conditions. The boilers were designed to handle 40,920 lb/hr of refuse having a lower heating value of 2,159 Btu/lb. The refuse furnace volumes of Units No. 28 and 29 are 17,655 ft^3 and 17,443 ft^3, respectively. The oil-furnace volume is 13,277 ft^3 in both units.

The noted difference between the two Stuttgart units is the grate designs. Unit 28 (Figure B-70) is equipped with a Martin grate, while Unit 29 (Figure B-71) is equipped with a roller grate that evolved from the Düsseldorf (VKW) design. Only bulky refuse is shredded before burning. Ferrous metals are removed from the residue magnetically.

It is interesting to note that the fly-ash emissions for the two Stuttgart boilers were expected to be identical, at 1.81 gr/SCF. The Martin grate furnace, Unit 28, closely approached this figure during TÜV testing, but the roller grate unit (Unit 29) emitted approximately 25% less fly-ash under similar test conditions. The grate areas are very similar, but the Unit 29 underfire air is approximately 35% lower than Unit 28. Nowak later published test data (Ref. B-108) that showed Unit 29 to be producing about 30% more flue gas particulates than Unit 28. Such variations must be expected, considering the nature of the fuel.

The two Stuttgart units are each equipped with one electrostatic precipitator of Rohtemühle design, similar to the aforementioned Lurgi units.

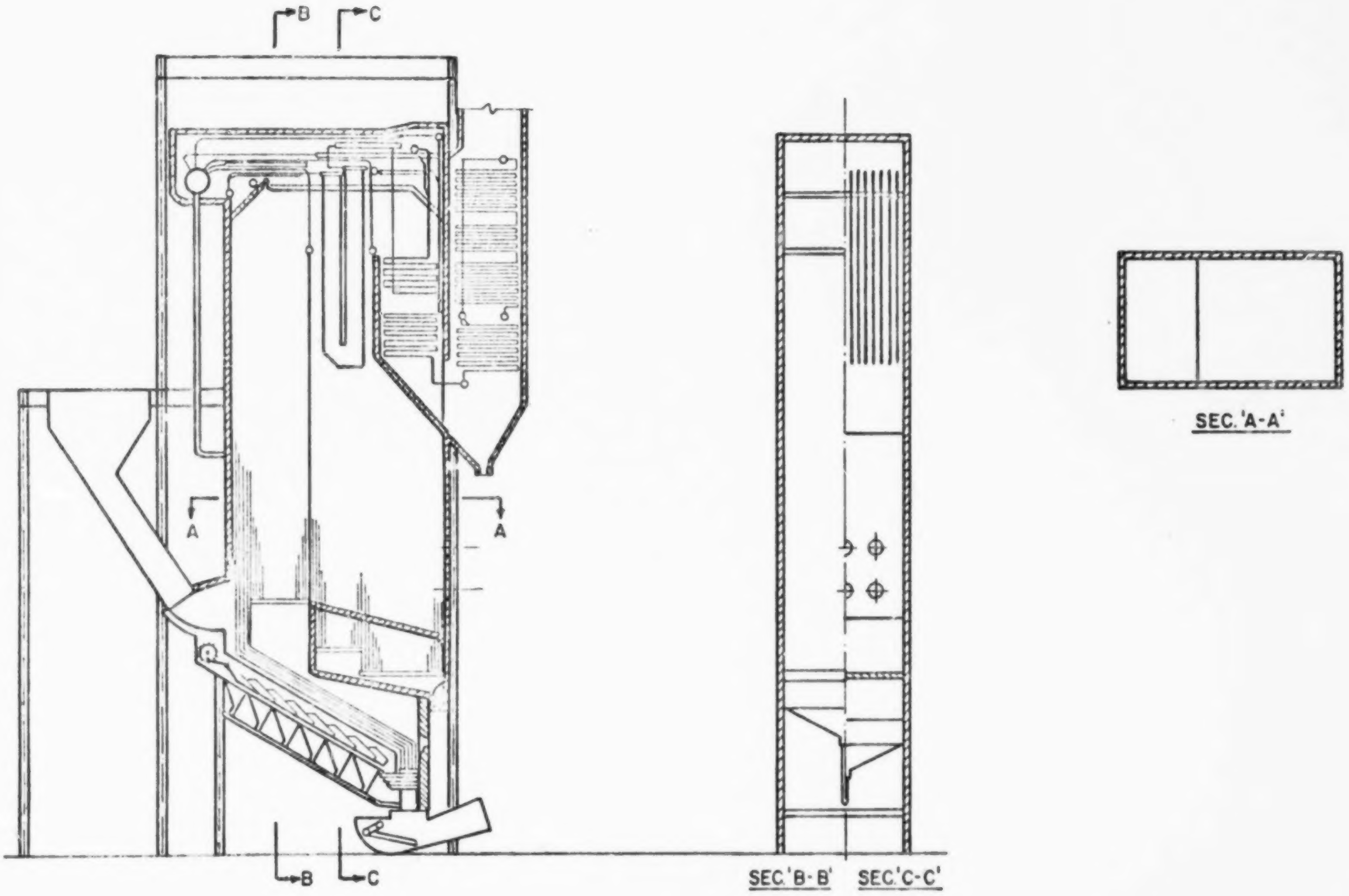
B
C
A
A
B
C
SEC.'B-B'
SEC.'C-C'
SEC.'A-A'

FIGURE B-70. STUTTGART COMBINED-FIRED STEAM GENERATOR - UNIT 28

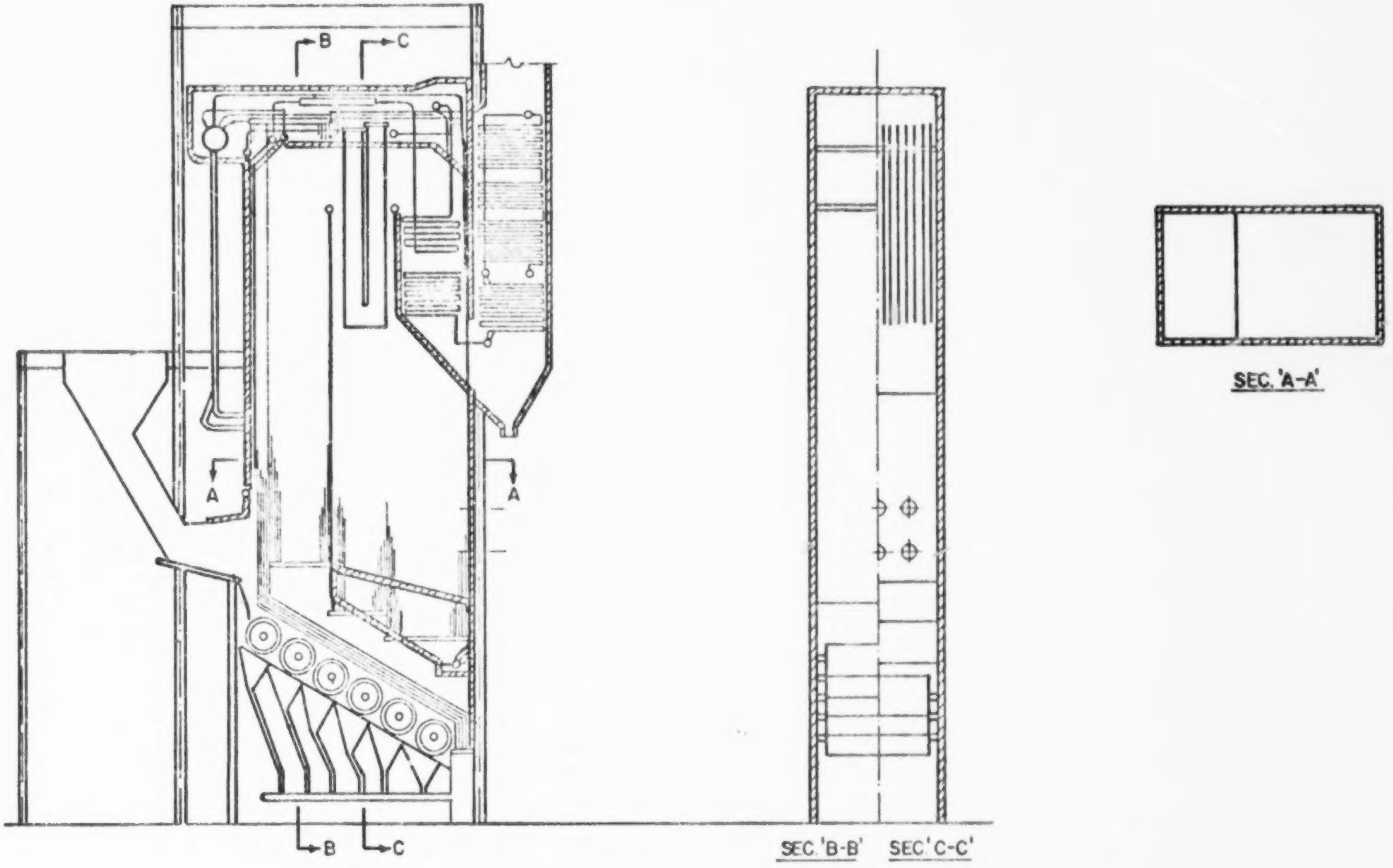
B
C
A
A
B
C
SEC. 'B-B'
SEC.' C-C'
SEC. 'A-A'

FIGURE B-71. STUTTGART COMBINED–FIRED STEAM GENERATOR - UNIT 29

C. DATA ANALYSIS; TECHNIQUES AND OBJECTIVES

A primary objective was to be able to predict, in quantitative terms, the nature of the emission problem that could be expected to result from the application, in domestic service, of refuse- or combined-fired system elements delineated by the study. This is obviously necessary in order to specify the required control techniques for such a system. Secondly, the reviews of both domestic utility practice and German combined-fired practice could form the basis for selecting with confidence the required control techniques. Finally, industrial experience must be brought to bear in the course of designing and cost-estimating the control systems required for each of the study's output-system recommendations.

Several techniques for predicting emissions from the systems under study can be proposed. The coal combustion side of the system, and its respective contribution to the particulate problem, can readily be predicted from existing technology (Ref. B-109). The refuse-caused component of the particulate problem might be predicted by employing Stenburg's (Ref. B-110) correlations of underfire air velocity vs. particulate emissions. Stenburg's correlation appears to have been substantiated by Neissen (Ref. B-111) and Walker (Ref. B-112) and is considered by some to be the most reliable single technique presently available for predicting emissions from grate-fired refuse. European investigators apparently have never attempted to relate underfire-air velocity to refuse fly-ash emissions. Many engineers, however, feel that other factors influence the generation rates of refuse fly-ash. These include the effects introduced by overfire air, uplift velocity above the grate, the presence or absence of a fossil-fuel flame envelope, and boiler-tube layout. Another factor, and a highly variable one, that influences fly ash production rate is the presence of discarded ash in the refuse itself.

The subject units under consideration were all tested under a variety of seasonal conditions:

Munich Block I	May 1965
Munich Block II	November 1967
Düsseldorf	September 1967
Stuttgart	July 1966

Quantitative refuse-compositions for each of the subject tests were not available. This is unfortunate because European refuse is characterized by much greater seasonal variations than is refuse in this country. This is probably due to a greater use of coal for home space-heating in Europe than is practiced in the U.S. This would result in correspondingly higher ash content in European municipal-refuse during winter months. Andritzky (Ref. B-113) observed that the Munich Block I plant emitted finer and higher levels of fly-ash during the winter months. He concluded that this was caused by the seasonal variation of the ash content in the input-refuse.

Table B-12 is an overall tabulation of the characteristics of the plants under consideration. Table B-13 is a detailed tabulation of the precipitator design data for these plants.

D. TÜV PERFORMANCE TESTS

1. Test Procedures

The TÜV conducted thorough evaluations of the boiler performance of the four selected generator plants. The TÜV reports, however, are essentially designed to demonstrate whether the equipment tested has met guaranteed specifications. In the context of the present program, the objective in studying these selected units was, of course, to establish the feasibility of using refuse as a steam-generator fuel and to determine what effect such a process would have on the emission of sulfur oxides. Because of the difference in objectives, the TÜV report data had to be reorganized in order to emphasize the operational parameters which pertain to this study. The primary information that was sought from these reports was data dealing with heat-, material-, and sulfur-balances. Because of its importance, sulfur balance is discussed in the main body of this report.

The TÜV reports do not develop detailed material balances, although mass outputs and inputs had been carefully measured. This was done because it was desired to estimate the heating value of the input-refuse based on thermal and fuel-consumption properties of the systems. It was felt that the heterogeneous nature of the fuel would make analytical determination of the heating value difficult and even then the results would not be accurate. From an algebraic point of view, the heating value of the fuel is not needed to determine unit efficiency.

Since, if Q_A = the sum of heat added to the system, except that from refuse

Q_S = useful steam output

Q_L = sum of heat losses

Q_R = heat from refuse combustion

Then $Q_R = Q_S + Q_L - Q_A$

and the steam generator efficiency is:

$$\eta = \frac{Q_S}{Q_R + Q_A}$$

TABLE B-12

GERMAN PLANT DESIGN DATA

	MUNICH NORTH		DÜSSELDORF	STUTTGART	
	Block 1 (2 Units)	Block II	4 Units	Unit 28	Unit 29
Furnace Type (Date Commissioned)	Combined-Fired Twin Chamber (1962)	Combined-Fired Single Chamber (1966)	Refuse Only (1965)	Combined-Fired Twin Chamber (1965)	Combined-Fired Twin Chamber (1965)
Refuse Grate					
Type	Recip. /Backward Feed	Recip. /Backward Feed	Roller or Drum	Recip. /Backward Feed	Roller or Drum
Manufacturer	Martin	Martin	VKW	Martin	VKW
Area, ft^2	605	1035	275	543	550
Charging Rate, lb/ft^2-hr	91	87	76	81	-
Btu Release, Btu/ft^2-hr (LHV)	455,000	435,000	378,000	410,000	404,000
Under-Fire Air, SCFM	-	-	- (Flue Gas Recirc.)	34,300 at Full Load	22,000 at Full Load
Refuse Rate,					
Short Tons/Day	660	1060	250	492	530
lb/hr	55,000	88,500	20,800	41,000	44,300
Aux. Fuel	Coal	Coal	None	Oil	Oil
Steam Condition					
Production 10^3 lb/hr	220	800	32	205	205
Pressure, psig	2600	2600	1280	925	925
Temp., ^oF (SH/RH)	1004/1004	1004/1004	932	977/-	977/-
APC Equipment					
Type	Elect. Pptr.	Elect. Pptr.	Elect Pptr.	Elect. Pptr.	Elect. Pptr.
Manufacturer	Lurgi	Lurgi	Lurgi	Rothemühle	Rothemühle
Rated Flow	-	Various	Various	172,000 ACFM	172,000 ACFM
Collection Efficiency	99.53%	99+%	99+%	98%	98%

TABLE B-13

ELECTROSTATIC PRECIPITATOR DESIGN DATA FOR GERMAN PLANTS

	MUNICH NORTH		DÜSSELDORF	STUTTGART	
	Block I	Block II		Unit 28	Unit 29
Number of Boilers/pptr	1	1	2	1	1
Number of Ducts	34	84	28	42	42
Duct Width, in.	9.5	-	8.5	8.75	8.75
Duct Height, ft.	24.6	27.4	20.6	25.4	25.4
Duct Length, ft.	29.1	31.5	18.9	16.4	16.4
Total Proj Coll Area, ft^2	48,700	-	21,800	35,000	35,000
Inlet Cross-Sect Area, ft^2	658	1810	406	780	780
Transformer-Rectifier Sets	Two-650 ma	Two	Two	One 500 ma	One 500 ma
Operating Voltage, kv d-c (max.)	76	-	-	-	-
Number Bus Sections	2/Series	2/Series x 2/Parallel	2/Series	2/Series	2/Series
Design Gas Velocity (max.). ft/sec	3.4	3.16	3.7	3.67	3.67

The TÜV tests were conducted in the following manner. The temperature, volume-rate, humidity, and pressure of the combustion air were measured. If this air were heated by a source that was not included in the control volume, the heat-content of the air would then have a heat-input term associated with it. The mass-rate of refuse burned was usually determined from a calibration curve of the current drawn by the refuse-crane vs the load lifted. The instantaneous current drawn by the crane at a specific height under known loads furnished the values that were used to plot the calibration curve.

The temperature of the residue was measured at the end of the grate by thermocouples. In units where the residue falls from the end of the grate into a quench tank, a heat input term is calculated to account for the water that evaporates from this tank and enters the furnace. The mass-rate of residue produced was measured and samples of the residue were analyzed to determine the level of combustibles still present after firing. The heat value of uncombusted combustible material and the sensible heat of the residue were then expressed as heat-loss terms.

The mass-rate, temperature, and combustible content of the fly ash were also measured. This was done in two ways. In some tests the mass of the collected fly ash was measured and samples of the waste gas were taken and analyzed. In the other method, an efficiency of the dust collector was assumed and the mass-rate of the fly ash in the raw gas was calculated using the measured mass of the precipitated fly ash. The moisture of the fly ash was also measured.

The levels of CO, CO_2, and O_2 were measured using an Orsat tester. The remainder of the waste gas was assumed to be N_2 (dry basis) for heat-balance purposes. The humidity of the waste gas was determined by drawing a sample of the waste gas through a cooler and into a Wulf bottle. From the weight of the condensate, the humidity of the waste-gas could be calculated.

Because the German practice is to establish the lower heating value, the heat loss from the wet waste gas was calculated as follows:

$$Q_{L(\text{waste gas})} = \left[\Sigma M_i C_{\rho_{i(T_2)}}\right] T_2 - \left[\Sigma M_i C_{\rho_{i(T_1)}}\right] T_1$$

where: C_{ρ_i} = specific heat of each constituent of the waste gas

T_2 = temperature of waste gas

T_1 = reference temperature

M_i = mass of each constituent of the waste gas

The heat loss due to the conduction and radiation of the boiler was estimated from standard charts, and the calculation of steam energy was done in accordance with usual practice. If a fossil fuel were fired with the refuse, its heat-input was calculated on the basis of an analytically determined heating value.

At Stuttgart, five tests were performed on each boiler. Three tests were performed using oil only as the fuel. This report considered only the two combined-firing tests done on each unit. The duration of each combined-firing test was 7.5 hours. One combined-firing test was accomplished at maximum continuous power-level (275,000 lb/hr steam), and one was at approximately half maximum continuous-load (165,000 lb/hr steam) for each boiler. All the combined firing tests were performed at the maximum refuse mass-rate. At Düsseldorf, one 24-hour test was performed. The power level of the unit was kept at maximum continuous-load (35,200 lb/hr steam). No oil was fired during this test.

2. Results

In all of the tests the total mass-output was found to be greater than the mass input. All the units tested were of balanced-draft design and thus the extra mass was attributed to air-leakage into the boiler.

The heat-balance and thermal-efficiency data in the TÜV reports were calculated on a lower heating value basis. Conversions were therefore made in the TÜV heat-balances to make them consistent with U.S. (higher heating value) practice. Additional heat-loss terms were also added to include the heat of evaporation of the water arising from the moisture and available hydrogen present in the fuels.

The percentage of moisture in the refuse was determined from water-balance derivations. The sum of the moisture and the water arising from the hydrogen in the refuse was found by subtracting all the water inputs (except that from refuse) from the water outputs. There are two methods for determining how much of this water is actually derived from the moisture in the refuse. One method is to assume a certain percentage of hydrogen in the refuse and to calculate the amount of water that would be formed from this hydrogen during combustion. Another method is to assume a heating value for the refuse. Using this heating value and the calculated lower heating value, the percent of combustible in the refuse can be determined. The ash-content can be derived from the mass-measurements of residue and fly ash; the remainder would then represent the percent of moisture in the refuse. The percent of moisture in the refuse was usually determined by the latter method.

The results of the TÜV tests and the data conversions that were employed, as described above, are summarized in Tables B-14 through -17. The first two present material-balance data while the last two consist of heat-balance information. In the following section, data are presented on the dust collector tests which were simultaneously conducted.

TABLE B-14

SUMMARY OF EFFICIENCY - TEST DATA FOR MUNICH UNITS - MATERIAL BALANCES

Plant/Unit	MUNICH NORTH BLOCK I			MUNICH NORTH BLOCK II				
Test Number	1	5	6	1	4	5	6	7
Firing Mode	Coal Only	Refuse + Coal	Refuse Only	Coal Only	Refuse Only	Refuse + Coal	Refuse + Coal	Refuse - Coal
Input:								
Combustion Air, lb/hr[1]	286,016	358,759	225,100	950,000	283,412	1,047,960	1,003,070	532,690
Aux. Fuel, lb/hr	25,199	15,388	0	74,580	0	57,280	56,460	16,755
Combustibles, %	83.1	84.4	-	85.9	-	86.6	86.7	86.6
Ash, %	6.2	5.9	-	6.4	-	6.6	6.2	6.5
Moisture, %	10.7	9.7	-	7.7	-	6.8	7.1	6.9
Refuse, lb/hr	0	59,337	57,536	0	100,310	94,140	86,640	98,845
Combustibles, %	-	26.3	25.6	-	35.2	32.3	31.5	30.6
Ash, %	-	41.2	30.0	-	36.8	36.9	44.6	39.8
Moisture, %	-	32.5	44.4	-	28.0	30.8	23.9	29.6
Output:								
Wet Waste Gas, lb/hr	376,560	394,544	287,970	1,030,850	366,820	1,163,130	1,119,000	581,620
Moisture Content, wt-%[2]	2.0	10.0	12.4	4.4	12.6	5.8	6.0	9.8
Waste Gas Comp., Dry Basis:								
O_2, %	6.30	6.70	11.88	14.35	6.50	5.75	5.45	6.70
CO_2, %	13.15	13.00	8.87	4.90	13.45	13.85	14.45	13.00
SO_2, %	0.05	0.03	0.019	0.048	0.106	0.094	0.09	0.09
N_2, %	80.50	80.26	79.22	80.70	79.94	80.31	80.01	80.16
CO, %	-	0.007	0.01	-	-	-	-	(HCl = 0.046%
Raw Flue Gas Fly Ash, lb/hr								
Ash	958	3,039	3,362	2,384	1,239	2,463	5,478	2,425
Combustibles	375	584	196	82	190	214	304	408
Furnace Residue, lb/hr								
Ash (excluding metals)	-	19,888	19,116	-	30,001	28,418	29,133	25,568
Combustibles	-	690	417	-	1,265	1,177	2,314	1,250
Metal (total)	-	1,197	1,193	-	2,815	3,500	3,585	3,005

---

1) Wet basis, except for Stuttgart units.

2) Other gas compositions are in vol-%; solid compositions are in wt-%.

TABLE B-15

SUMMARY OF EFFICIENCY - TEST DATA FOR DÜSSELDORF AND STUTTGART UNITS - MATERIAL BALANCES

Plant/Unit	DÜSSELDORF	STUTTGART UNIT NO. 28			STUTTGART UNIT NO. 29		
Test Number	1	1	4	5	1	4	5
Firing Mode	Refuse Only	Oil Only	Refuse + Oil	Refuse + Oil	Oil Only	Refuse + Oil	Refuse + Oil
Input:							
Combustion Air, lb/hr[1]	92,358	291,000	365,113	252,424	320,769	345,020	252,558
Aux. Fuel, lb/hr	0	19,392	12,090	6,505	19,672	13,466	6,116
Combustibles, %	-	-	-	-	-	-	-
Ash, %	-	-	-	-	-	-	-
Moisture, %	-	-	-	-	-	-	-
Refuse, lb/hr	23,192	0	53,131	46,385	0	49,240	47,487
Combustibles, %	33.9	-	43.6	30.5	-	30.3	31.8
Ash, %	33.7	-	25.9	28.5	-	31.3	30.6
Moisture, %	32.4	-	30.5	41.0	-	36.4	37.6
Output:							
Wet Waste Gas, lb/hr	113,007	283,220	421,917	303,860	313,050	412,032	312,273
Moisture Content, wt-%[2]	9.9	8.0	10.3	11.2	5.9	11.3	10.5
Waste Gas Comp., Dry Basis:							
O_2, %	11.20	1.43	4.42	6.26	1.35	5.04	7.42
CO_2, %	8.41	14.59	13.33	12.14	14.67	12.90	11.41
SO_2, %	0.046	-	-	-	-	-	-
N_2, %	80.30	83.98	82.21	81.59	83.90	82.06	81.17
CO, %	(HCl = 0.046%)	-	0.04	0.01	0.08	-	-
Raw Flue Gas Fly Ash, lb/hr							
Ash	1,028	-	1,030	605	-	1,383	1,394
Combustibles	72	-	143	44	-	120	120
Furnace Residue, lb/hr							
Ash (excluding metals)	6,078	-	11,241	10,979	-	12,095	11,411
Combustibles	564	-	185	326	-	345	375
Metal (total)	728	-	-	-	-	-	-
Separated Ferrous Metal	-	-	1,056	1,005	-	1,490	1,303

1) Wet basis, except for Stuttgart units.

2) Other gas compositions are in vol-%; solid compositions are in wt-%.

TABLE B-16

SUMMARY OF EFFICIENCY - TEST DATA FOR MUNICH UNITS - HEAT BALANCES

Plant/Unit	MUNICH NORTH BLOCK I			MUNICH NORTH BLOCK II				
Test Number	1	5	6	1	4	5	6	7
Firing Mode	Coal Only	Refuse + Coal	Refuse Only	Coal Only	Refuse Only	Refuse + Coal	Refuse + Coal	Refuse + Coal
Input (excl. refuse), 10^3 Btu/hr								
Heat from Aux. Fuel (HHV)	322,689	200,100	0	994,120	0	765,500	758,600	226,360
Sensible Heat of Aux. Fuel	-	-	-	-	-	-	-	-
Atomizer Steam	-	-	-	-	-	-	-	-
Air Heat	-	-	-	-	-	-	-	-
Steam Heat from Residue	-	-	-	-	-	-	-	-
Total (A)	322,689	200,100	0	994,120	0	765,500	758,600	226,360
Steam Output, 10^3 Btu/hr (B)	287,402	276,207	92,044	881,020	223,547	890,660	856,910	391,296
Losses, 10^3 Btu/hr (C)								
Wet Waste Gas	13,602	21,850	15,780	71,779	33,383	87,682	84,190	37,801
Heat of Vap. of Moisture & Comb. Fuel - H_2	16,272	45,796	31,650	42,750	47,470	91,723	65,130	64,966
Residue & Fly Ash	5,873	25,769	17,033	939	16,438	17,191	22,130	21,653
Conduction & Radiation	2,165	2,284	2,161	2,816	2,709	2,994	2,830	2,661
Total Losses (C)	37,913	95,699	66,624	118,284	100,000	199,590	174,280	127,081
Output, 10^3 Btu/hr (B + C)	325,315	371,906	158,668	999,304	323,547	1,090,250	1,031,190	518,377
Thermal Efficiency (η), % (100B/B + C)	88.4	74.3	58.0	88.2	69.1	81.7	83.1	75.5
Refuse Input, lb/hr (D)	0	59,337	57,536	0	100,310	94,140	86,640	88,845
Refuse Heating Value (HHV - Calc'd), Btu/lb (B + C - A/D)	-	2,900	2,757	-	3,225	3,450	3,146	3,287
Steam Production, 10^3 lb/hr	224	214	82	-	-	775	752	315

TABLE B-17

SUMMARY OF EFFICIENCY - TEST DATA FOR DÜSSELDORF AND STUTTGART UNITS - HEAT BALANCES

Plant/Unit	DÜSSELDORF	STUTTGART UNIT NO. 28			STUTTGART UNIT NO. 29		
Test Number	1	1	4	5	1	4	5
Firing Mode	Refuse Only	Oil Only	Refuse + Oil	Refuse + Oil	Oil Only	Refuse + Oil	Refuse + Oil
Input (excl. refuse), 10^3 Btu/hr							
Heat from Aux. Fuel (HHV)	0	365,217	228,091	122,738	370,079	253,344	115,057
Sensible Heat of Aux. Fuel	-	1,543	1,098	607	1,309	1,091	622
Atomizer Steam	-	178	139	147	127	159	155
Air Heat	543	6,175	6,484	5,564	9,300	5,667	3,708
Steam Heat from Residue	480	-	1,507	1,646	-	2,546	2,411
Total (A)	1,023	373,113	237,319	130,702	380,815	262,807	121,953
Steam Output, 10^3 Btu/hr (B)	40,478	323,149	324,280	198,166	335,431	314,591	192,681
Losses, 10^3 Btu/hr (C)							
Wet Waste Gas	12,964	25,333	38,079	27,288	21,079	40,022	30,714
Heat of Vap. of Moisture & Comb. Fuel - H_2	10,501	24,334	40,846	31,765	20,836	43,222	29,937
Residue & Fly Ash	7,567	103	6,575	6,575	1,257	8,086	8,162
Conduction & Radiation	1,562	1,642	1,701	2,114	1,654	1,590	1,685
Total Losses (C)	32,594	51,412	87,201	67,742	44,826	92,920	70,498
Output, 10^3 Btu/hr (B + C)	73,072	374,561	411,481	265,908	380,257	407,511	263,179
Thermal Efficiency (η), % (100B/B + C)	55.4	86.3	78.8	74.5	88.2	77.2	73.2
Refuse Input, lb/hr (D)	23,192	0	53,131	46,385	0	49,240	47,487
Refuse Heating Value (HHV - Calc'd). Btu/lb (B + C - A/D)	3,107	-	3,278	2,915	-	2,939	2,974
Steam Production, 10^6 lb/hr	-	272	270	165	279	263	161

E. EMISSION-CONTROL (ELECTROSTATIC PRECIPITATOR) EQUIPMENT

1. Performance Characteristics

With the exception of gaseous emission control, the legislation and enforcement aspects governing emission control in Germany are similar to those of this country. The specification for allowable dust emission is, however, more strict. Regulation VDI-2114, November 1966, limits incinerators of over 20 tons per day to an absolute fly-ash emission of 150 mg/Nm^3 (0.061 gr/SCF) uncorrected for CO_2. Stack opacity requirements are also made based on Ringlemann indices.

The firm of Lurgi Apperatebau of Frankfurt was commissioned to design the fly-ash collection system for the first combined-fired (coal-plus-refuse) power boiler (Munich North Block I). Due to considerations of particle size and fly-ash resistivity, Lurgi felt that the refuse-derived component of the fly ash would be somewhat easier to control via electrostatic precipitation than that from low-sulfur coal.

In Europe, precipitators for low-sulfur coal fly ash are typically operated under 260° F. This is well below the flue gas temperatures around 310° F associated by some U.S. observers with peak resistivity and, thus, minimum collection efficiency. Lurgi, however, expected refuse fly ash to be more tractable and regarded operation at peak-resistivity as acceptable. In keeping with this, Lurgi's performance guarantee on the combined-firing system was based on a precipitator design migration-velocity (precipitation rate) of 0.222 ft/sec. This compares to a value of 0.130 ft/sec for coal-only firing of the same system. The latter value dictates that a precipitator be sized 50% larger than would be required for a combined-firing installation. The 0.222 ft/sec design migration-velocity for combined firing resulted in a guaranteed collection-efficiency of 99.25%. In actual test at Munich Block I, collection performance was measured at 99.75%, corresponding to an actual migration-velocity of 0.301 ft/sec. The operation on coal-only was also much better than anticipated in the guarantee. Compared to a design migration-velocity of 0.130 ft/sec for a guarantee collection efficiency of 97.54%, the unit was tested at 99.56%, corresponding to an actual migration velocity of 0.203 ft/sec.

Lurgi guaranteed, on the basis of an average design migration-velocity of 0.363 ft/sec, that the Düsseldorf units would perform at 98.90%. Under actual test conditions (gas temperatures of 450° - 460° F), the precipitators were found to have a 99.68% collection efficiency, corresponding to an average actual migration-velocity of 0.402 ft/sec.

At the third installation, Munich North-Block II, Lurgi decided that for combined firing at similar temperatures the precipitator design migration-velocity could be raised from 0.222 ft/sec (design, Block I) to an average of 0.265 ft/sec. This resulted in guaranteed collection efficiencies of 99.5% and above. Under actual test, the precipitator performed at 99.72% and higher, corresponding to an average actual migration-velocity of 0.295 ft/sec. This value is slightly lower than the performance of the Block I precipitator (0.301 ft/sec actual), presumably because of the lower dust-output.

For coal-only firing at Block II, Lurgi's guarantee was again improved, in spite of the fact that an operating temperature of 310°F (peak resistivity) was permitted. The migration-velocity was increased to 0.153 ft/sec as compared to the design-value of 0.125 ft/sec for Block I. Under actual test, however, the unit not only met the guarantee but performed better at 310°F than the Block I units did at 260°F. It was demonstrated from these test data that the fly ash produced in these units exhibited a lower temperature peak resistivity than is considered typical (300° - 310°F) for this country. This is shown in Figure B-72.

It is also interesting to note that U.S. investigators (Ref. B-112) have reported fly-ash resistivity values of 10^{11} ohm-cm, at approximately 410°F, for refractory-wall, municipal refuse-incinerators. Corresponding values for European water-walled furnaces are reported (Ref. B-107) at 6×10^7 ohm-cm at 432°F. A comparison of the precipitation rates is shown in Figure B-73. This significant difference is probably related to the composition of the respective fly ashes.

The relationship of fly ash resistivities to temperatures for German fly ash from both low-sulfur coal and refuse appears to be significantly different from that of similar U.S. counterparts (Refs. B-112 and B-114). This indicates that pollution control design parameters for any proposed combined-fired systems for use in this country cannot be directly based on European practice.

Values of resistivity vs. temperature for U.S. plants dictate that a minimum gas temperature of 450°F be selected for electrostatic precipitator operation with municipal-refuse fly ash, whether heat recovery is practiced or not. These data also indicate that precipitators must be more conservatively sized than are European systems.

2. Design Factors

The materials of construction of the precipitators and flue work in the German precipitators are plain carbon steel. Fly ash collecting and storage hoppers are pyramidal. These and the dry, pneumatic, ash-handling systems are typical of those favored in utility practice, but in sharp contrast with U.S. refractory-incinerator practice. Experience in the latter field indicates that dust transport properties are such that live bottom devices are required under electrostatic precipitators. These may take the form of trough-hoppers with screw-conveyors, chain-drag equipped flat-bottoms, or agitated slurry-ponds integral with the precipitator. The operation of

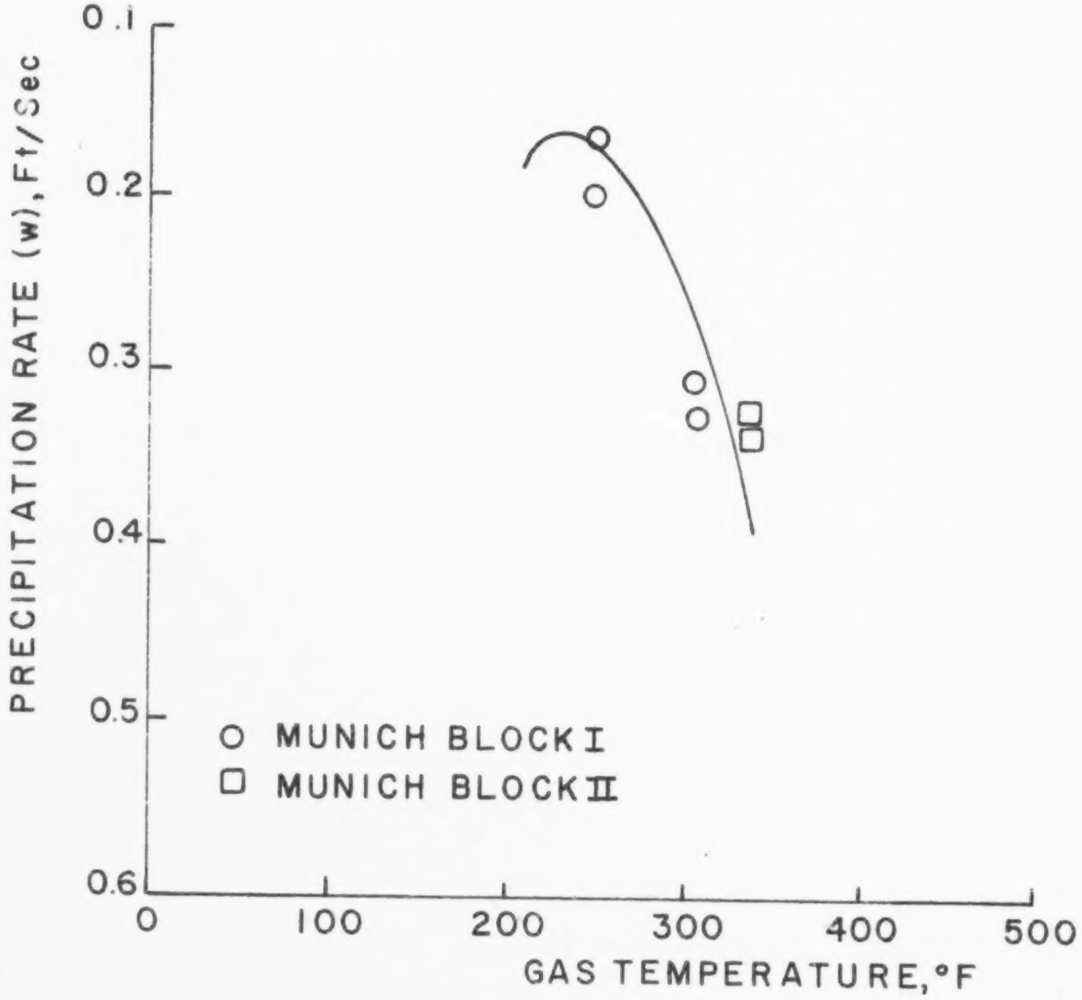

FIGURE B-72. PRECIPITATOR PERFORMANCE VS GAS TEMPERATURE - MUNICH PLANTS

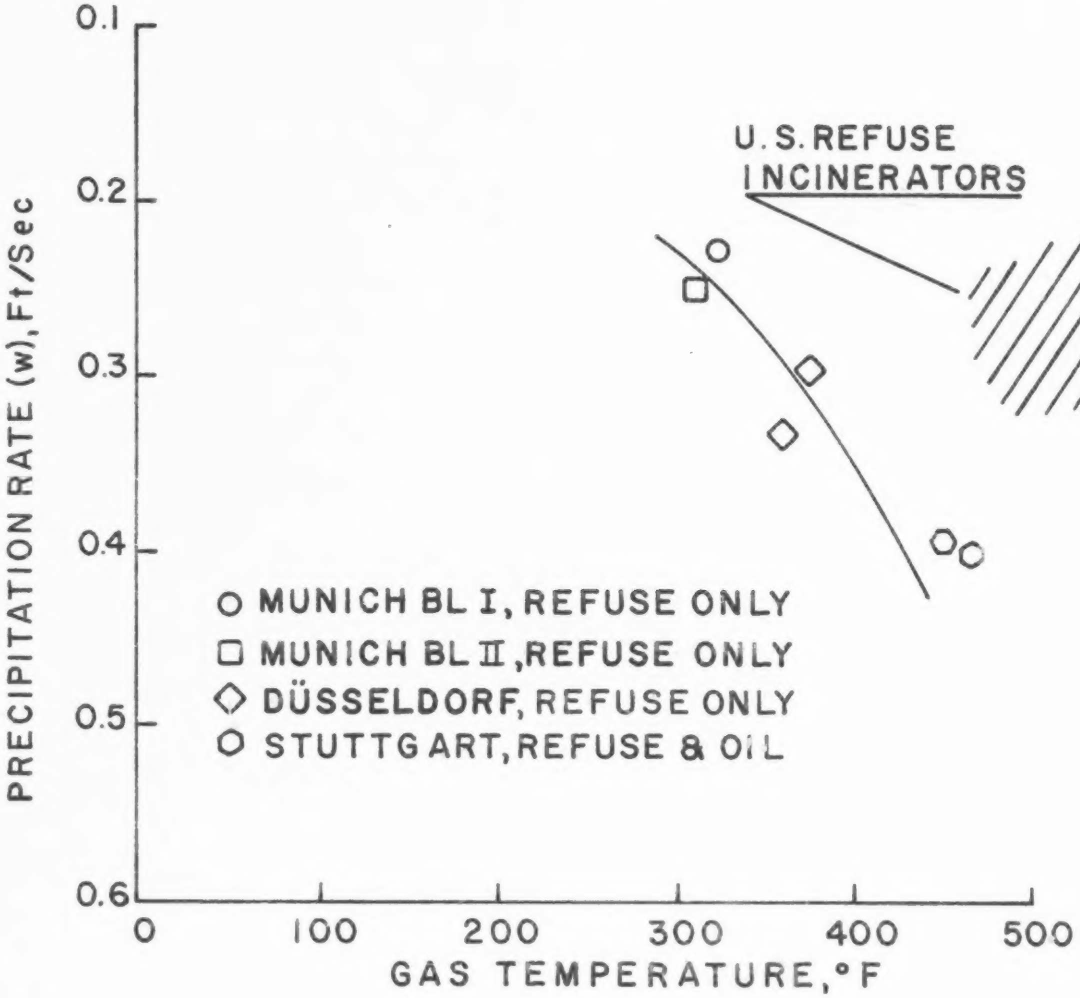

FIGURE B-73. PRECIPITATOR PERFORMANCE VS GAS TEMPERATURE - GERMAN AND U.S. DATA domestic refractory units has also dictated that more sophisticated materials of construction be used throughout to combat corrosion. Finally, extensive gas tempering must be employed (Ref. B-115) to depress gas temperatures if lower cost materials of construction are to be used successfully.

In both domestic and European utility practice, reliability and availability considerations promote the use of multiple electrical sections within electrostatic precipitators. In the event of an electrical malfunction, sectionalization permits the isolation and shutdown of only the impaired section. All of the German precipitators discussed here are equipped with two electrical sets, or transformer-rectifiers, each with its own control system that automatically regulates power-input to maintain preset levels of electric field-intensity or density. The exact feedback conditions are not detailed in the available data in the case of the German control systems. It is known, however, that European precipitator manufacturers equip their U.S. installations with automatic voltage controls that maintain a preset level of sparking within the precipitator. Random or occasional sparkover is considered a good indicator of optimum field-strength and power-input.

Somewhat in contrast to U.S.-manufactured equipment, the European precipitator design-approach aims at a more conservative migration velocity by using somewhat lower field intensities. Thus, the size of the precipitator must be increased commensurately. As a result of this, lower gas velocities, 3 to 4 ft/sec, are employed in combined-fired applications. U.S. designers would typically specify gas velocities of 4 to 4-1/2 ft/sec for refractory incinerators. It must be cautioned, however, that gas velocity is selected for a discrete particle size distribution so that re-entrainment problems are minimized.

One final difference that has been historically observed between European and U.S. precipitator designs is the degree of electrical sectionalization. Two electrical sections in series were standard in the German units studied. U.S. suppliers would incorporate 3 or 4 sections, in series, for similar requirements.

3. Performance Guarantees

The European performance guarantees state that collection efficiency must be expected to decrease with decreasing inlet dust-loading, presumably because re-entrainment losses remain fairly constant in the face of varying loadings. Correction curves are also presented that show how collection efficiency will increase with decreasing flow rate. This is due to higher residence time in the precipitator. The guarantees further state that gas temperature will be maintained through certain limits, or performance will decrease. Finally, the combustible content of the ash must be maintained within certain limits, or else performance will be impaired. This follows from the effects carbon combustibles are known to produce on ash resistivity.

The guarantee situation on the domestic scene is seemingly not as sophisticated. U.S. suppliers normally guarantee a performance level at one point, and not through a range of operating conditions. However, the actual selection of design parameters is more of a proprietary art in the U.S. than in Europe. The European literature abounds with information on resistivity as a function of process variables (e.g., Refs. B-115 to -118) and migration-velocity selection.

F. TÜV DUST COLLECTOR TESTS

With one exception, precipitator inlet and outlet dust determinations were done by isokinetic sampling. TDI test methods are used by the TÜV. Four alternative sampling trains are employed, depending on the velocity of the flue gas at the point of sampling. The VDI test procedures conform closely with ASME Power Test Codes PTC 21, 27, and 28. In the case of the Düsseldorf tests, flue layout prohibited reliable sampling. Inlet loading was therefore calculated on the basis of the outlet loading and the precipitator hopper-catches. The TÜV calculate dust collector efficiency on a mass-differential basis:

$$\text{Efficiency} = \frac{\text{inlet concentration-outlet concentration}}{\text{inlet concentration}}$$

This is in agreement with U.S. practice, except that in this country concentration values are always corrected to standard gas conditions (32°F and 760 torr). The TÜV data were not consistently in this form. Where necessary, therefore, dust concentrations were corrected to standard gas conditions but not to a standard CO_2 level. An overall summary of the dust collector test data is presented in Tables B-18 and -19. The tabulation includes calculated data comparing the design vs. actual precipitator performance. Precipitation rates, electrical energization data, and gas velocities are included. The tests shown were all performed at full boiler steaming-load.

1. Particulate Emissions

a. Concentrations

Measured fly ash concentrations for the subject plants ranged from a minimum value of 1.10 gr/SCF for the Stuttgart Unit 29 to a maximum of 8.64 gr/SCF for Munich Block I while in combined-firing (refuse + coal) operation.

If one subtracts 0.15 gr/SCF for the oil-derived component of the Unit 28 Stuttgart lowest fly ash emissions (Test No. 1, Table B-19), the resultant value for the refuse-derived fly ash emissions is 1.62 gr/SCF. This compares with a measured emission of 1.66 gr/SCF for Munich Block II (Test No. 7, Table B-18) when firing refuse-only. Both units are equipped with Martin reciprocating grates. The Munich Block II emissions

TABLE B-18

SUMMARY OF DUST-COLLECTOR PERFORMANCE DATA FOR MUNICH UNITS

Plant/Unit	MUNICH NORTH BLOCK I					MUNICH NORTH BLOCK II						
Test Number	1/1	1/2	2/1	2/2	3	1	2	3	4	5	6	7
Firing Mode	Coal Only		Coal & Refuse		Refuse Only	Coal	Coal	Coal (Low Load)	Coal+40TPH Refuse	Coal+40TPH Refuse	Coal+4 TPH Refuse	Refuse Only
Rated Gas Volume, 10^3 ACFM (°F)	98(284)	98(284)	132(320)	132(320)		343(302)	343(302)	343(302)	423(338)	432(338)	432(338)	432(338)
Actual Gas Volume (Measured at Pptr Outlet), 10^3 ACFM	110(247)	113(257)	147(310)	147(310)	108(315)	346(308)	348(313)	245(284)	419(324)	432(336)	384(326)	403(328)
Percent of Rating	112	115	111	111	--	101	101	71.3	96.8	100	88.7	93.5
Anticipated Pptr Inlet Dust Conc, gr/SCF	1.97	1.97	1.97/6.95	1.97/6.95	6.95	2.19-8.75	2.19-8.75	2.19-8.75	2.19-8.75	2.19-8.75	2.19-8.75	2.19-8.75
Actual (Test) Pptr Inlet Dust Conc, gr/SCF	2.39	2.44	5.12	8.64	6.76	1.18	1.51	9.51	3.06	3.06	3.24	1.66
Actual (Test) Pptr Outlet Dust Conc, gr/SCF	0.0105	0.0325	0.0128	0.0178	0.00774	0.0089	0.0166	0.0060	0.0103	0.00503	0.00896	0.0133
Guaranteed Collection Efficiency[1]	97.94	97.49	99.25	--	--	97.97	98.00	99.55	99.55	99.50	99.72	99.54
Actual (Test) Collection Efficiency, %	99.56	98.67	99.75	99.79	99.89	99.24	98.90	99.37	99.65	99.84	99.72	99.20
Pptr Design Gas Velocity at Rated Volume, ft/sec	2.48	2.48	3.35	3.35	--	3.15	3.15	3.15	3.98	3.98	3.98	3.98
Pptr Actual (Test) Gas Velocity, ft/sec	2.77	2.86	3.714	3.714	2.73	3.19	3.21	2.26	3.86	3.99	3.55	3.72
Relative Pptr Size (Design) Based on Rated Flow, sec/ft	29.80	29.80	22.07	22.07	--	25.41	25.41	25.41	20.18	20.18	20.18	20.18
Relative Pptr Size (Actual) Based on Actual Flow, sec/ft	26.68	25.88	19.91	19.1	27.10	25.22	25.05	35.64	20.33	20.16	22.74	20.58
Precipitation Rate (W):												
(design), ft/sec	0.130	0.124	0.222	--	--	0.153	0.154	0.213	0.268	0.263	0.291	0.267
(actual), ft/sec	0.263	0.167	0.301	0.323	0.251	0.193	0.180	0.142	0.271	0.319	0.258	0.235
Pptr Electrical Energization Data:												
A) Secondary Voltage Inlet (Inlet/Outlet), kv	41.2/44.4	40.8/43.7	30/34	31/34	32/33	38.2/37/2	37.2/37.8	--	32.2/32.6	30.5/32.2	32.2/32.2	32.2/32.8
B) Secondary Amperage (Inlet/Outlet), ma	260/308	240/381	600/560	640/650	640/650	850/940	585/775	--	750/720	735/870	600/660	620/684
C) Input Power (Inlet/Outlet), kw	10.7/13.7	9.79/16.6	18.0/19.0	19.8/22.1	20.5/21.4	26.5/34.9	21.8/29.3	--	24.2/23.5	22.4/28.0	19.3/21.3	20.0/22.4
D) Power Density (Inlet/Outlet), Watts/10^3 ACFM	103/126	90.6/154	128.6/136	141.7/157.9	198.8/208	76.9/101	62.5/84.2	--	57.8/56.2	51.9/64.8	50.3/55.3	49.5/55.7
E) Power Density (Inlet/Outlet), Watts/Ft^2	0.220/0.281	0.201/0.342	0.370/0.391	0.407/0.454	0.421/0.440	0.183/0.241	0.150/0.202	--	0.167/0.162	0.155/0.193	0.133/0.147	0.138/0.155
F) Field Strength (Inlet/Outlet), kv/in.	0.87/0.94	0.86/0.92	0.63/0.72	0.65/0.72	0.68/0.70	0.80/0.77	0.77/0.80	--	0.68/0.69	0.65/0.68	0.68/0.68	0.68/0.69

1. Corrected for test conditions per Manufacturer's correction factors.

TABLE B-19

SUMMARY OF DUST-COLLECTOR PERFORMANCE DATA FOR DÜSSELDORF AND STUTTGART UNITS

Plant/Unit	DÜSSELDORF		STUTTGART			
			Unit 28		Unit 29	
Test Number	1	2	1	2	3	4
Firing Mode	Refuse	Refuse	Refuse & Oil	Refuse & Oil	Refuse & Oil	Refuse & Oil
Rated Gas Volume, 10^3 ACFM (°F)	93(500)	93(500)	172(410)	172(410)	172(410)	172(410)
Actual Gas Volume (Measured at Pptr Outlet), 10^3 ACFM	91(455)	92(468)	164(375	133(375)	169(362)	117(360)
Percent of Rating	97.7	98.9	95.2	77.4	98	67.6
Anticipated Pptr Inlet Dust Conc., gr/SCF	3.94	3.94	1.81	1.81	1.81	1.81
Actual (Test) Pptr Inlet Dust Conc, gr/SCF	4.81	5.69	1.67	1.83	1.47	1.10
Actual (Test) Pptr Outlet Dust Conc, gr/SCF	0.0158	0.0184	0.0169	0.0207	0.0210	0.00283
Guaranteed Collection Efficiency[1]	98.85	98.95	98.5	99.5	97.9	99.5
Actual (Test) Collection Efficiency, %	99.67	99.68	98.22	98.87	98.57	99.74
Pptr Design Gas Velocity at Rated Volume, ft/sec	3.82	3.82	3.68	3.68	3.68	3.68
Pptr Actual (Test) Gas Velocity, ft/sec	3.74	3.77	3.51	2.85	3.61	2.49
Relative Pptr Size (Design) Based on Rated Flow, sec/ft	14.00	14.00	12.17	12.17	12.17	12.17
Relative Pptr Size (Actual) Based on Actual Flow, sec/ft	14.32	14.16	12.79	15.73	12.42	18.02
Precipitation Rate (ω):						
(design), ft/sec	0.408	0.319	0.328	0.435	0.317	0.435
(actual), ft/sec	0.399	0.406	0.315	0.285	0.342	0.330
Pptr Electrical Energization Data:						
A) Secondary Voltage Inlet (Inlet/Outlet), kv	31.5/29	31/29	--	--	26.5/21.8	26.8/22.4
B) Secondary Amperage (Inlet/Outlet), ma	265/267	313/310	--	--	484/588	503/575
C) Input Power (Inlet/Outlet), kw	8.3/7.7	9.7/9.0	--	--	12.8/12.8	13.5/12.9
D) Power Density (Inlet/Outlet), Watts/10^3 ACFM	91.7/85	105/97.7	-- --	-- --	79.7/79.6	121/116
E) Power Density (Inlet/Outlet), Watts/ft^2	0.401/0.372	0.466/0.432	--	--	0.366/0.366	0.385/0.368
F) Field Strength (Inlet/Outlet), kv/in.	0.74/0.68	0.73/0.68	--	--	0.61/0.50	0.61/0.51

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[1] Corrected for test conditions per manufacturer's correction factors.

are lower than would be anticipated on the basis of underfire-air considerations alone. This is undoubtedly due to a superior burn-out being effected in this boiler.

In considering the VKW roller grates units at Düsseldorf ant Stuttgart (Unit 29), strikingly different emissions (refuse-only firing) are apparent: a measured average of 5.25 gr/SCF at Düsseldorf vs. 1.13 gr/SCF at Stuttgart. The latter figure includes a 0.15 gr/SCF subtraction for oil-derived ash.

An absolute value of 22,000 SCFM underfire air at full load is available at Düsseldorf. The heat-release rate of the Stuttgart roller grate is lower than for the Düsseldorf grate, so that a lower refuse-derived level of emissions can be expected at Stuttgart. The wide spread between these values (5.25 vs. 1.13 gr/SCF) is apparently not solely explicable on the basis of underfire-air. Other variables, such as furnace velocities and time vs. temperature profiles, are suspected as being contributory.

A final interesting comparison, mentioned earlier, is that between the Martin and VKW grates in the otherwise-identical Stuttgart units. The roller-grate unit produces 25% lower dust concentrations, while being fired with 30% less underfire-air.

All of the foregoing tends to support the conclusions of Stenburg (Ref. B-110), Neissen (Ref. B-111), and Walker and Schmitz (Ref. B-112); that is, the type of grate, and even the degree of agitation the fuel is subjected to, is of little or no consequence in influencing particulate levels. They feel that underfire-air velocity and refuse composition, expressed as SCFM/ft^2 of grate, vs. emissions per lb of combustible burned, is the main factor in determining particle loading.

The velocity of underfire-air is not, however, the only controlling parameter. The low emissions of the Munich Block II unit and Stuttgart Unit 29 cannot be explained on that basis. Clearly, furnace geometry plays a significant role in determining particulate emissions. Qualitatively speaking, however, analysis of the TÜV data indicates that lower furnace gas-velocities and higher residence-times result in significantly lower particulate emissions.

b. Fly-Ash Sizing and Combustibles

Particle size distributions were expressed by the TÜV (Refs. B-104 to -108) in suspension-velocity categories. These data were therefore converted to equivalent particle diameters based on a suspension velocity of 0.6 cm/sec for a 10μ particle. Additionally, actual sieve and Bahco analyses had been performed on integrated hopper samples from Munich Block II and Düsseldorf by other investigators (Ref. B-111). These data are combined in Table B-20. The values range from 5% ($<10\mu$) for Block II units, to 20% ($<10\mu$) for Düsseldorf.

TABLE B-20

PROPERTIES OF FLY ASH FROM GERMAN PLANTS

	Particle Size Dist. % Less Than Indicated Size (μ)	% Combustibles (A) = Refuse Only (B) = Combined Firing	Bulk Resistivity Ohm - cm (^{o}F)
Munich North Block I	Not Available	6.5% (A) 15% (B) 20% - 30% (B)	Not Available
Munich North Block II	5% (10)[1]	3.4%[2] (B)	2×10^{9} (320)[1]
Düsseldorf	13% (10) (TUV Test-1) 23% (10) (TUV Test-2) 20% (10)[1]	6.6% (A)	6×10^{7} (432)
Stuttgart 28	Not Available	9.7% (B)	Not Available
Stuttgart 29	Not Available	8.3% (B)	Not Available

1) - Source: Ref. B-111
2) - Source: Ref. B-119

Refuse fly-ash emitted during grate combustion might be expected to become coarser as the input-rate is increased. This follows from the idea that the bed emits greater amounts of material (and of increasing size and mass ranges) as the underfire air is increased. This prediction is complicated by burnout considerations, however, The percent combustibles in the fly ash, as the latter elutriates from the bed, will also influence the ultimate size of the particles which leave the furnace. Finally, furnace geometry also determines the degree of ultimate burnout achieved for any given particle in suspension.

The lower fly ash emissions from either Munich Block II or Stuttgart would be expected to be characterized by low combustible contents and small particle diameters. As the data in Table B-20 indicate, this is not completely true. The Block II unit furnished the lowest emission rate, and the best apparent burnout (lowest combustibles). Despite this, the Block II ash is reported as being coarser than that from other sources. It is possible, of course, that the hopper-catch samples were not representative.

c. Ash Resistivity

Absolute values for fly ash resistivities were not given in the TÜV test reports. Values for Munich and Düsseldorf have been reported by another investigator (Ref. B-120) and were included in Table B-20.

These values were determined using integrated hopper-catch samples from the respective installations. Again, the samples cannot be considered as being truly representative. Owing to the selective behavior of the precipitator, resistivity values of truly representative samples could logically be expected to be significantly higher. Additionally, the value reported for Munich could not be associated with a specific mode of fuel-firing. It can be assumed, however, that combined-firing, the normal operating-mode of this unit, was probably being practiced when the fly ash was produced. These resistivity values determined for Munich Block II and Düsseldorf are in an excellent region for the cost-effective application of electrostatic precipitation.

2. Gaseous Emissions

Compared to the situation in this country, there is less reason for German national concern over control of sulfur-oxides pollution. European coal is notably low in sulfur (less than 1%). Fuel-oil burned in Europe is also low in sulfur for the most part. Based on the limited data available, derivations of sulfur-balances were made. This subject is discussed in the main volume of the report.

G. EUROPEAN FIELD TRIP

1. Scope of Activities

Observations were made and discussions held during a July 1969 survey of selected refuse disposal facilities in Germany, France, and England by project personnel. No attempt was made to view each of the major European refuse operations, in that such general surveys have been reported previously and adequate descriptive literature is available on many of the facilities. What was intended was an examination of representative steam generating incinerators and refuse-processing equipment, along with interviews of key personnel experienced in their operating, such that specific details on the cataloging of design system candidates could be thoroughly considered. In addition, it has become apparent that personal expediting of approval for the release of several of the requested acceptance test reports of the Technischer Überwachungs-Verein (TÜV) was required.

As a result of the trip, all necessary TÜV approvals were obtained and groundwork was laid for obtaining additional reports of other units or for potential additional testing of units in the future. In the TÜV documents obtained, the survey team had access to steam generator and electrostatic precipitator reports from five different units, rather than on two combined-firing units as had originally been planned.

Most of the information obtained has already been documented in the present appendix or in other volumes of the report. Information was also obtained, however, on refuse-firing plants other than the five German plants just described. Comments on these additional facilities are therefore presented in the next section. Table 19 lists the itinerary followed, the facilities visited, and the key personnel contacted.

2. Other Refuse-Fired Plants Visited

a. Essen-Karnap Plant

The prime purpose in visiting this plant was to inspect the Lindemann shear and also a refuse-burning travelling grate (for comparison with agitating grates). This plant was originally designed for firing pulverized-coal and modified to burn, in addition, sewage sludge and refuse. Perhaps the most interesting aspects of this plant are that it is a total-waste facility and that it is one of the few plants built and operated by a private utility.

In this area all sewage is delivered to the Emse river (parallel to the Ruhr river), from which open system it is later withdrawn for treatment. Purified water is finally released to the Ruhr river. The classification sludge is brought to the plant on a long conveyor belt. An interesting feature of the continuous belt is that it is twisted at each end so that the belt rollers located below the belt are always in contact with the unused side of the belt.

TABLE B-21

EUROPEAN FIELD-TRIP ITINERARY

Date, 1969	City	Facility Visited	Personnel Contacted
14 July	Düsseldorf	Vereinigte Kesselwerke AG (VKW)	Dipl.-Ing. R. Mutke Ing. F. Förster Ing. Grad. H. Hartmann
15 July	Essen	Rheinisch-Westfälisches Elektrizetätswerk AG (RWE), Essen-Karnap Power Plant	Ing. F. Förster Obering. W. Drewes
		Technischer Überwachungs-Verein Essen e. V. (TÜV)	Dr.-Ing. K. Schwarz
		VKW	Mr. Schiemann
		Deutsche Babcock	Dipl.-Ing. O. Engler
16 July	Berlin	Zentralstelle für Abfallbeseitigung des Bundesgesundheitsamtes (ZfA)	Prof. Dr. Langer Dipl.-Ing. H. W. Leonhardt Dipl.-Ing. P. Wagenknecht
		Berlin-Ruhleben Refuse-Incineration Plant	Dipl.-Ing. L. Barniske
17 July	Munich	Elektrizitätswerk München	Dipl.-Ing. F. Maikranz
		Munich South Plant	Dr.-Ing. H. Bachl Dipl.-Ing. F. Maikranz
		Josef Martin Feuerungsbau GmbH	Dipl.-Ing. W. J. Martin Obering. H. Weiband
		TÜV Bayern	
		German Consultant*	Dr.-Ing. M. Andritzky
18 July	Stuttgart	Technische Werke der Stuttgart, Stuttgart-Münster Plant	Dipl.-Ing. F. Nowak
		VKW	Dipl.-Ing. E. Wied

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*To Foster Wheeler Corp.

TABLE B-21 - Continued

Date, 1969	City	Facility Visited	Personnel Contacted
21 July	Mannheim	Friesenheimer Island Plant	Ing. Grad. H. M. Hillsheimer
	Heidelberg	Composting Pilot Plant	Oberbaurat. Hortsmann
22 July	Frankfurt	Battelle Institut, e. V.	Dipl. -Ing. R. Rasch Dr. F. Fink
		Refuse Burning Plant	Ing. H. Thode Dipl. -Ing. H. Baumann
23 July	Wiesbaden	Landfill Station	Direktor Steeg
	Bad Godesberg	U. S. Consulate	Mr. N. L. Pazdral
24 July	Duisberg	Composting Plant	Stadtbaudir. B. Frechen
		VKW	Obering. K. Nuber
25 July	Paris	Société Foster Wheeler Francaise	Mr. M. de Trincaud Mr. B. J. Loygue
		Traitment Industriel des Résidus Urbains (TIRU)	Mr. J. Deféche
		Issy-les-Moulineaux Plant	Ing. M. Tourret
		Ivry Plant	Ing. M. Tourret Mr. Fourment
28 July	London	Foster Wheeler John Brown Boilers, Ltd.	Mr. R. M. V. Beith Mr. R. A. C. Bromwich
	Surbiton, Surrey	Tollemache Composting Systems, Ltd.	Dr. D. H. G. Tollemache Mr. G. F. Robinson
	Chertsey, Surrey	Chertsey Urban District Council - Landfill Plant	Mr. W. S. Moncrieff Mr. H. Bliczek
29 July	Old Woking, Surrey	Woking Urban District Council-Pulverizing Plant	Mr. Hall
30 July	Epsom, Surrey	Epsom District Council-Pulverizing Plant	Mr. Brownjohn

Essentially three types of refuse are delivered to the plant. Municipal refuse is brought in by regular municipal trucks. Bulky refuse is also delivered, usually by private vehicles, and is processed by a Lindemann Shear. Industrial chemical refuse is accepted in a special pit or in liquid-storage tanks. Reduced bulky-refuse is discharged to the same pit where municipal refuse is dumped. There are doors at each truck stall which open just far enough for the truck to discharge. An inclined apron is provided so that the refuse crane cannot possibly hit a truck or door. The pit, which is some distance from the refuse-burning facility, is designed to be under negative pressure, but the odor near the pit-building is quite noticeable.

A feature of this plant is that the raw refuse is sent to a magnetic separation-step prior to delivery to the furnace. The recovered metals are collected, baled, and removed daily. The metal is used in a foundry producing cast iron; the small amount of tin present in this scrap is apparently considered acceptable for this iron. This certainly does not apply in the case of steel production. It was pointed out that metal baled after combustion contains a great deal of ash which has to be removed before using the metal in a melt. For this reason, the scrap commanded a price of $10/ton, a 50% premium over burned scrap.

From the metal separation step, the refuse is delivered by conveyor belt to the boiler house, where there are ten steam-generators delivering steam to five steam-turbines. Five of the steam generators have been modified to burn refuse. The other five are fired on sludge. Boiler 3 was modified in 1961, boilers 1 and 2 in 1969, and boilers 6 and 7 in 1964; total capital costs for the refuse-handling modifications amounted to $6.2 million. Both the clarification-sludge and the refuse are brought to the respective furnaces by conveyor belt; 2000 tons of refuse and a like quantity of sludge are handled daily.

Each of the five refuse-furnaces is completely refractory-enclosed, with no heat-absorbing surface. The flue gas of the combusted refuse is vented to the water-cooled boiler at a point below the tangential coal burners. Average heating value of the refuse is 2160 Btu/lb (LHV); the highest noted was 2880 Btu/lb (LHV). It was confirmed that this plant had never experienced any corrosion of tube surfaces in any of the units. The only tube wastage attributable to refuse-firing resulted when occasionally the refractory furnace was overloaded and the flame impinged on the water walls of the steam generator.

Recovery of ash, both bottom residue and fly ash, is well handled. German regulations do not permit the use of fly ash for making concrete, while Dutch specifications are not restrictive. Almost all of the fly ash collected (1000 tpd) is sold for $0.37/ton to Dutch distributors, who haul it to Holland in their own trucks, where they receive $1.87/ton from ultimate users.

With regard to a private utility (RWE - see Table B-21) handling refuse, it was pointed out that the operation was somewhat forced upon them by the local municipality. The RWE agreed to handle refuse in exchange for providing power to some sections of the area previously served by municipal power. It was explained that the RWE is compensated for handling the refuse and sludge in a rather complicated manner, which assures a normal return on the investment.

When queried about the future possibilities of private utilities, such as RWE, building refuse-burning plants, RWE management was quite sure that none would be built. The reasoning was quite straightforward. It was claimed that a coal-fired steam generator can be operated with essentially one man, while a combined-fired unit requires fourteen men. It was also pointed out that even if better systems could be developed, the private utilities would probably not be very interested. It is more advantageous from both a production and economic viewpoint to build large power plants near the source of fuel and transmit power to the load centers. According to RWE the only reason why Germany has been in the forefront of refuse burning is because most large cities have municipally-owned and -operated power plants. However, the private utilities are desirous of providing the power presently generated by the municipalities. A gradual take-over of municipal power systems by the private utilities is foreseeable. This would then suggest that private utilities would be required to operate existing refuse-burning plants.

A large combined-firing plant similar to that at Essen-Karnap was planned for the Cologne area and described in 1965 in a special issue, devoted to refuse-incineration, of Brennstoff-Wärme-Kraft. The fact that plans for this plant never materialized is perhaps an indication of this trend.

b. Berlin-Ruhleben Plant

This plant is rather unique because it is actually three plants in one. It is a refuse-incineration plant, a clinker-processing plant, and a clinker-sintering plant. The completed structures will eventually include six boilers. To date, four are operating and two are in the construction stage. Steam is delivered to the existing Reuter power plant across the river. Superheated steam is delivered at or above 905°F (940 psig); the steam-flow chart indicated considerable flow-variation. The arrangements with the power plant involve two rates of payment. A lower payment is given when the steam temperature falls below 905°F. When this occurs the steam from the refuse-burning plant is diverted from the high-pressure-turbine to the intermediate-pressure turbine. It is claimed that this is automatically controlled.

The plant has suffered some corrosion in the furnace, due to localized reducing-atmospheres. An increase in the excess air used has virtually eliminated this corrosion. Along the roller-grates in this furnace are waterwall tubes which eventually become part of the side wall. These tubes have also suffered some wastage. This type of construction is also used in Stuttgart and Mannheim but more for the purpose of abrasion protection than for heat pickup. While some wastage has been noted at Stuttgart, none was reported at Mannheim. Some tubes in the Berlin-Ruhleben plant have failed because of longitudinal cracks. In several places, ash had collected behind the tubes, which thus were being pushed out into the furnace. These units do not have welded walls. There was heavy ash-accumulation in the superheater, although no plugging had yet occurred. It was claimed that the refuse in Berlin contains more ash than in most other German cities.

A novel refuse-feeding arrangement, consisting of a continuous, tank-track conveyor, is used between the chute and the furnace grate. Most European plants use table-type feeders. Generally, these feeders are not used in the U.S.

The sintering plant had not been as successful as expected. When product from this plant was mixed with concrete, cracks developed in the cured material. This had not been a problem during pilot plant evaluations. The cause is believed to be elemental aluminum. Apparently aluminum-foil has been marketed only recently in Berlin. It is claimed that the aluminum passes through the furnace unoxidized and failure of the concrete is caused by the reaction of the free metal with the alkaline cement slurry. After working with Battelle on this problem, it is now believed that by washing the residue in lime solution the aluminum can be dissolved. The sintering plant was not operating when visited, although charts in the control room indicated that the plant is operated at least several days each month.

c. Munich-South Plant

This plant was indeed the cleanest and most impressive plant seen on the trip. The combined refuse/natural gas facility is Unit No. 6. The other units are coal-fired boilers. Unit No. 5 has been ordered and will be a duplicate of No. 6, although construction had not yet begun. In the control room the steam-flow trace was seen to be very smooth, exhibiting much less variation than did the units in the Munich-North plants. The grate used in this unit was a Martin design, the refuse-furnace was by VKW, and the natural-gas-fired steam generator was constructed by Deutsche Babcock. This unit also has a capability for future coal-firing, although the bunkers and mills have not yet been installed in the space provided.

The flue gas leaving the refuse-fired economizer is too hot for introduction into the electrostatic precipitator. It is therefore mixed with the cooler flue gas produced by the natural-gas-fired boiler. If only refuse is burned, the flue gas will have to be cooled by water sprays.

Only refuse collected by municipal trucks is brought to this plant. Bulky refuse is handled by special trucks equipped with built-in shredders. The importance of having at least that degree of control over refuse size was stressed. The residue is removed by conveyor belt and is first taken to a magnetic separator. Baled scrap is loaded into railroad cars and residue is taken to landfill by truck. Double doors are employed at the refuse pit, with interlocks provided to prevent both doors from opening simultaneously. Air is withdrawn from the top of the pit. As in Berlin, one could not smell any refuse unless standing at the edge of the pit. An interesting point on the architecture is that there are several floors of offices located above the unloading dock. The crane operators were located in a pulpit at the top of the pit, similar to the Berlin operation. The pulpit was located at an elevation even with the chute. However, unlike the Munich-North plants and the Essen-Karnap plant, it is physically possible for the crane to hit an unloading truck unless a stop on the bridge of the crane is provided.

d. Mannheim Plant

The Mannheim plant is located on Friesenheimer Island in the Rhine river; there are some industrial complexes on the islands as well as a landfill. When the 4-year old refuse-burning plant is not operable, refuse trucks are diverted to the landfill; steam demands are fulfilled by operating standby, oil-fired boilers. At the time the installation was planned, the various grates available were studied but none of them was considered particularly well suited for refuse-burning. The choice of a traveling-grate was based simply on the fact that it was the cheapest machine available. It was found to be advantageous, however, to use several grates in order to achieve some agitation by tumbling. When the plant was first started some corrosion was noted, but it appears to have subsided somewhat. The convection sections of the steam generator, several of which have staggered-tube arrangements, are similar to the Stuttgart unit; it would therefore seem that erosion may have been as much the cause of tube-wastage as corrosion.

This unit is similar to the units at Berlin and Stuttgart, in the use of several rows of waterwall tubes parallel to the grate for abrasion protection. At Mannheim, however, the feedwater is first sent through these tubes before flowing to the economizer. At Berlin and Stuttgart, the abrasion-protection tubes are part of the boiling section. It was claimed that no failure of these abrasion-protection tubes had occurred at Mannheim. It would appear likely that tube-wastage of this section would be dependent upon metal temperature.

On the day of the visit, one unit was out of service for a scheduled outage. In this unit, part of the superheater is built in the upper quarter of the side-wall. This superheater surface was being removed and replaced by waterwalls. The other unit was down on an unscheduled outage for repair of the grate.

As at the other plants visited, the Mannheim Plant was equipped with electrostatic precipitators. As in Stuttgart, a Hazemag shredder was used to reduce bulky waste.

e. Frankfurt am Main Plant

Here, plant management admitted that some corrosion problems had been experienced but not of an unmanagable degree. The steam produced here is for district-heating and hot water supply (through heat exchangers) in an adjacent apartment-house complex. The steam produced by refuse-burning is an auxiliary source to that from conventional, oil-fired boilers. One of the unique features of the refuse-burning units is that the refuse from the crane is dumped on a vibrating trough, which in turn discharges to a vertical chute. While an interesting feature, it is doubtful that it is a necessary one. No other plants are known to have such an arrangement, and all appear to work well without it. As in other plants, the pit and building have been built with a view to future capacity requirements. With extra pit-capacity, the operators try to stagger refuse deliveries on a weekly basis, so that they maintain some week-old refuse. It is claimed that more uniform burning is achieved by mixing aged and fresh refuse. The furnace volume was found to be extremely generous, and no overfire air was used. Judging from the fact that the excess air was nearly 100% and the flames produced were somewhat lazy and spotty, the grate surface-area was probably oversized. The residue from this plant revealed much unburned material, including partially-burned paper. As in Munich, trucks with built-in shredders were employed, in lieu of stationary shredding equipment at the plant.

The most persistent maintenance problem mentioned involved the crane cables which had to be replaced every few weeks. The cranes in this plant were equipped with an automatic control system, so that once a bucket was loaded the charge could be automatically taken and discharged at a predetermined chute. However, in the automatic-mode the crane could move in only one direction at a time. This resulted in an unacceptably slow feeding-rate. Manual operation, in which simultaneous tridirectional control is routinely achievable, had to be adopted therefore.

f. Issy-les-Moulineaux Plant

This plant is located near the Seine, just outside of Southwest Paris. It contains four refuse-fired, natural-circulation boilers, which utilize auxiliary fuel (oil) only on start-up. The rated plant-capacity is 60 tph while operating at steam conditions of 770°F and 925 psig.

Samples of refuse, amounting to approximately 5 tons, are taken 10 days of the year. It is claimed that samples taken during the summer indicate heating values higher than the steam generator calculated heating value. During the winter, analyzed samples are lower than calculated by records. The furnace exit temperature is maintained below 1000°F. The average LHV is 3600 Btu/lb. The minimum LHV is 1600 Btu/lb. The grate metal temperature is between 300 and 400°F. In this plant, as in some other plants, a siftings-hopper is located under the table feeder. Uncompressed, recovered metals are sold for $18/ton.

In-line tube spacings were used throughout the convection sections. The air is heated in a steam-coil air heater. The first corrosion noted occurred after 5,000 hours, while superheater trouble occurred after 14,000 hours.

Refuse is collected by municipalities or private contractors. The plant receives money from the municipalities at the end of the year and the amount is dependent, in part, on the plant operation. The budget amount set by the TIRU is $8.10/ton.

g. Ivry Plant

This plant is also located near the Seine, but outside of Paris to the southeast. The plant had just started up one steam generator and the other was scheduled for completion by October 1969. The operating unit was still undergoing some tests and it was not possible to observe the steam-flow traces. The designed operating conditions are 875°F and 1400 psig, using natural-circulation boilers. Like the Issy plant, a reciprocating grate is employed and refuse constitutes the sole fuel used, except on start-up.

Upon completion, Ivry will be the world's largest refuse-fired steam generation facility, with the two furnaces being able to handle 2400 tons/day. The completed plant cost will be $30 million.

As elsewhere, the pit operators are located in a pulpit. However, at Ivry the pulpit is located at a point lower than the chute. The operator has therefore been provided with a closed-circuit television and constantly has a view of the chute on the screen.

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APPENDIX C

COST MODEL

I. INTRODUCTION

The following sections discuss in detail the data and equations that were developed and incorporated into the cost model computer program. Three basic models have been developed: (1) combined firing plant, (2) conventional firing plant, and (3) a transportation model. Each model has been derived as a series of equations describing the cost of equipment, fuel, labor, and other cost variables as a function of the major design parameters (waste load, electrical generating capacity, waste fraction). In addition to the equation form, each major cost element is also portrayed in graphical form to facilitate analysis of the model. Unless otherwise referenced, cost data presented in this appendix is based on information provided by Foster Wheeler, Research-Cottrell, and A. E. Gosselin, Consultant to Aerojet-General. The effective base date for all costs is July 1969.

II. COMBINED FIRING PLANT MODEL

The results of a series of conceptual design studies have been incorporated into a cost model that represents an estimate of the cost of each major piece of equipment and operating expense in the combined firing plant. The model generates costs from the receiving area through the disposal of the incinerator residue. The costs are divided into capital costs, annual capital costs, operation and maintenance costs, and residue disposal costs.

A. CAPITAL COSTS

The total capital costs represent the investment in equipment and/or facilities that are required by a waste-fossil fuel power generating plant. A summary of the cost elements and estimated equipment life is given in Table C-1. Where applicable, the cost elements have been grouped according to the FPC codes. Elements not fitting under a particular code are listed separately. Specifics concerning each element are presented in the following paragraphs.

1. Land and Land Rights

The unit cost of land is treated parametrically. The land area required is a function of power output and the quantity of waste handled. It was estimated that approximately 37 acres plus 6.5 acres per 100 MW would be required for the power plant and that an additional 2 acres would be required for each 1000 tons per day of waste. This leads to the following equation:

$$C_{LC} = \left(0.065\ P_T + 37 + \frac{W_w}{500}\right) C_A$$

Where: C_{LC} = capital cost of land, dollars

C_A = unit cost of land, dollars per acre

W_w = waste load, tons per day

P_T = total plant output power, megawatts

TABLE C-1

ESTIMATED EQUIPMENT LIFE

FPC CODE	DESCRIPTION	ESTIMATED LIFE, YEARS
310	Land and Land Right	Infinite
311	Structures and Improvements	20
312	Boiler Plant Equipment	
	Steam Generator	20
	Water Treatment Equipment	25
	Pumps	10
	Piping	20
	Coal Handling Equipment	25
	Residue Handling Equipment	20
	Stacks	25
314	Turbine-Generator Equipment	25
315	Accessory Electrical Equipment	15
316	Miscellaneous Power Plant Equipment	
	Miscellaneous Equipment	25
	Power Plant Cranes	15
	Air Pollution Control Equipment	20
	Waste Handling Equipment	
	Receiving and Storage Equipment	25
	Scales	15
	Shredders	10

Figure C-1 shows land costs as a function of power and processed waste load with the unit cost of land set at $10,000 per acre.

2. Structures and Improvements

The capital cost of structures and improvements includes building substructure and superstructure, piling, structural steel, painting, landscaping, roads, railroad siding fencing, sewers, and site preparation. Since a plant capable of handling solid waste may require several steam generators, the structure cost is obtained by solving the basic equation at a power level equivalent to the individual steam generator and then multiplying this by the number of steam generators to the 0.9 power. The 0.9 power is to take into account that even though the structures are larger, the appurtenances would not increase directly with the number of steam generators. The cost equation then is:

$$C_{SF} = 5.06 \times 10^4 \left[\frac{P_T}{(N_s)_{i,j}} \right]^{0.755} (N_s)_{i,j}^{0.9}$$

where: C_{SF} = cost of structures and improvements

$(N_s)_{i,j}$ = number of steam generators at power level i and waste fraction j

Figure C-2 shows structure costs as a function of power and the number of steam generators used. The number of steam generators required depends on the design as shown in Tables C-2 through C-9.

3. Boiler Plant Equipment

The capital cost of boiler plant equipment includes, in addition to the steam generator, the following auxiliary items: boiler water treatment, pumps, piping, coal and residue handling equipment, and stacks. Auxiliary boiler equipment is discussed separately in the next section.

Steam generator costs were estimated for ten different design configurations designated Cases 1 through 10; these have been described in Section III, B of Volume I. The design criteria for each of these cases are shown in Tables C-2 through C-9. The items included in the steam generator cost estimates are shown in Table C-10. As shown in the tables, costs were developed at several power levels and refuse fractions for cases 1, 2, 3, 6, 7, 8, and 9. Due to the nature of cases 4, 5, and 10, only one refuse fraction (f_w) was considered. In order to use the data presented in these tables in the computer program, equations were fit to each set of cost data.

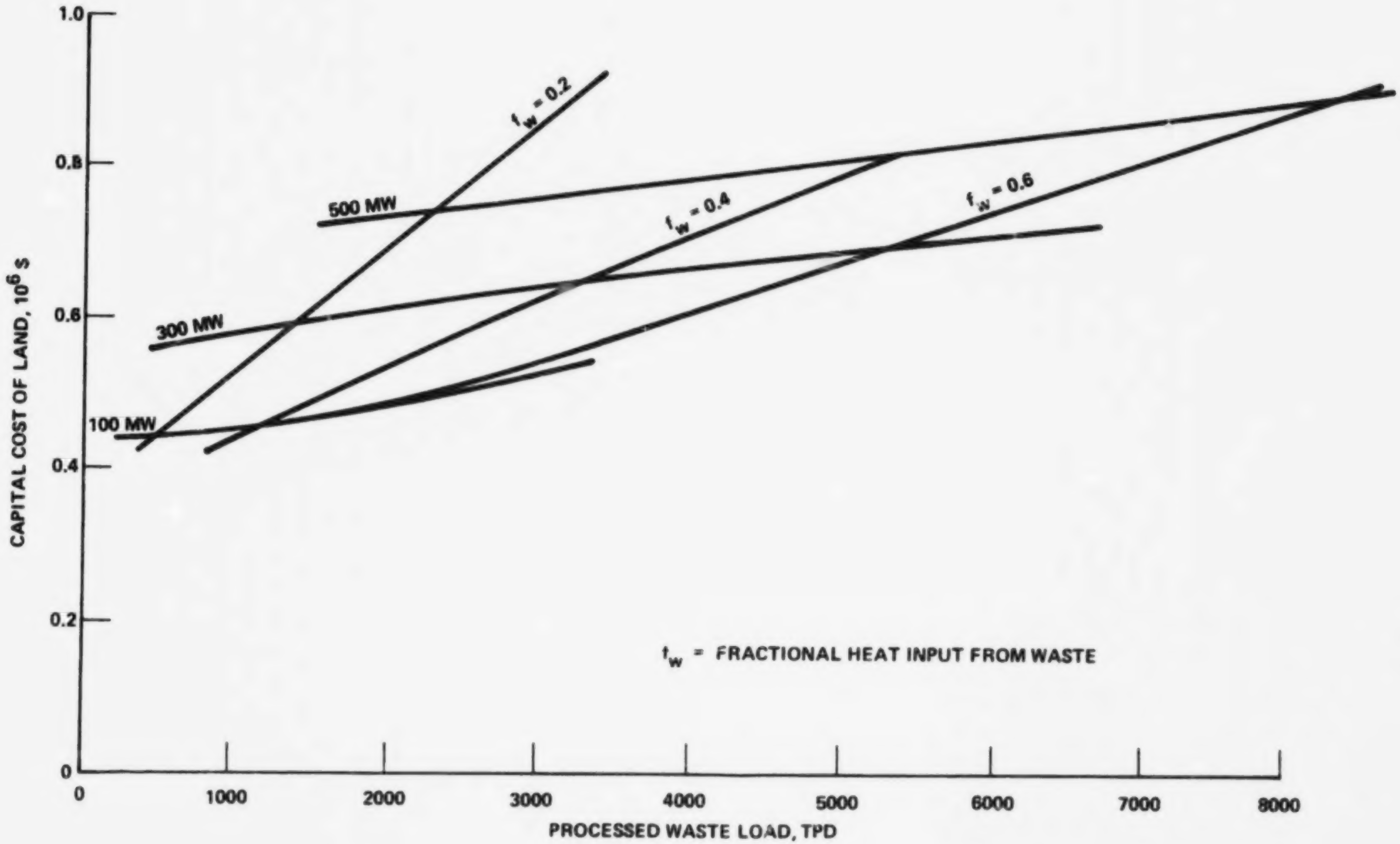


FIGURE C-1. CAPITAL COST OF LAND

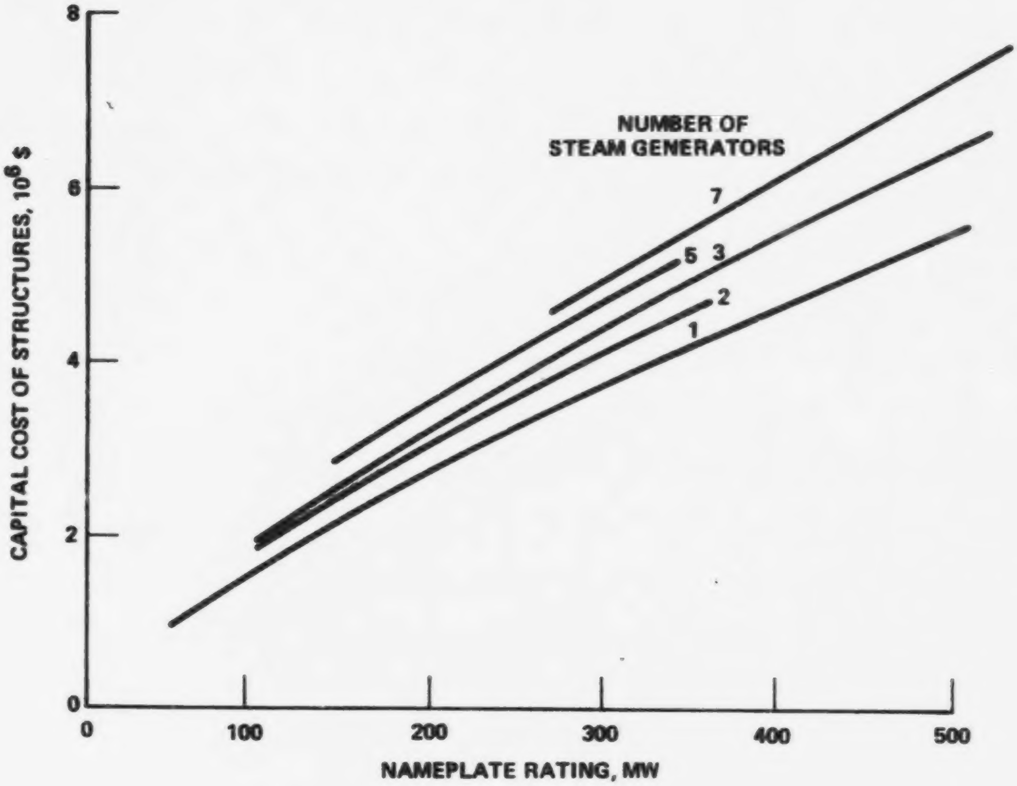


FIGURE C-2. CAPITAL COST OF STRUCTURES

TABLE C-2 - CASE 1

STEAM GENERATOR DESIGN AND COST INFORMATION

Nameplate Rating, MW	100	200			300	400			500
Refuse Rate, %	40	20	40	60	40	20	40	60	40
Steam Pressure, psig	1250	1800	1250	850	1250	1800	1250	1250	1250
Number of Steam Generators	2	2	3	5	5	3	6	9	7
Number of Turbines	2	1	3	5	4	2	5	5	6
Steam Generator Cost, 10^6 $	13.0	15.8	24.2	37.5	34.5	26.2	42.6	59.6	51.0

TABLE C-3 - CASES 2 AND 8

STEAM GENERATOR DESIGN AND COST INFORMATION

Nameplate Rating, MW	100	200			300	400			500
Refuse Rate, %	40	20	40	60	40	20	40	60	40
Steam Pressure, psig	1250	1800	1250	850	1250	1800	1250	1250	1250
Number of Steam Generators	2	2	3	5	5	3	6	9	7
Number of Turbines	2	1	3	5	4	2	5	5	6
Steam Generator Cost, 10^6 $	10.4	13.3	17.4	24.2	27.6	23.0	34.2	44.7	41.1

TABLE C-4 - CASE 3

STEAM GENERATOR DESIGN AND COST INFORMATION

Nameplate Rating, MW	100		200		300			400			500		
Refuse Rate, %	10	16.6	10.1	16.6	10.4	20.2	24.9	9.9	20.4	24.9	10.6	20.3	24.9
Steam Pressure, psig	1800	1800	1800	1800	2400	2400	2400	2400	2400	2400	2400	2400	2400
Number of Steam Generators (Refuse)	1	1	1	1	1	2	3	2	3	3	2	4	4
Number of Turbines	1	1	1	1	1	1	1	1	1	1	1	1	1
Steam Generator Cost, 10^6 \$	7.6	8.2	12.0	13.4	15.9	20.6	21.0	20.5	23.6	25.3	24.2	29.5	31.6

TABLE C-5 - CASE 4

STEAM GENERATOR DESIGN AND COST INFORMATION

Nameplate Rating, MW	100	200	300	400	500
Refuse Rate, %	63.5	63.5	58.3	58.3	58.3
Steam Pressure, psig	1800	1800	2400	2400	2400
Number of Steam Generators (Refuse)	3	5	6	7	9
Number of Turbines	1	1	1	1	1
Steam Generator Cost, 10^6 $	14.4	22.9	28.5	34.9	42.7

TABLE C-6 - CASE 5

STEAM GENERATOR DESIGN AND COST INFORMATION

Nameplate Rating, MW	100	200	300	400	500
Refuse Rate, %	75.5	75.5	71.3	81.3	71.3
Steam Pressure, psig	1800	1800	2400	2400	2400
Number of Steam Generators (Refuse)	3	5	7	9	11
Number of Turbines	1	1	1	1	1
Steam Generator Cost, 10^6 $	15.1	22.8	28.9	37.0	44.7

TABLE C-7 - CASES 6 AND 7

STEAM GENERATOR DESIGN AND COST INFORMATION

Nameplate Rating, MW	100	200			300	400			500
Refuse Rate, %	40	20	40	60	40	20	40	60	40
Steam Pressure, psig	1250	1800	1250	850	1250	1800	1250	1250	1250
Number of Steam Generators	2	2	3	5	5	3	6	9	7
Number of Turbines	2	1	3	5	4	2	5	5	6
Steam Generator Cost, 10^6 \$	9.3	12.8	16.4	22.5	24.8	22.3	31.6	42.0	34.2

TABLE C-8 - CASE 9

STEAM GENERATOR DESIGN AND COST INFORMATION

Nameplate Rating, MW	100	200				300	400			500
Refuse Rate, %	40	20	40	60	80	40	20	40	60	40
Steam Pressure, psig	1800	1800	1800	1250	1250	1800	1800	1800	1250	1800
Number of Steam Generators	1	1	2	3	4	2	2	3	5	4
Number of Turbines	1	1	1	3	3	2	2	2	5	3
Steam Generator Cost, 10^6 $	7.6	11.3	14.8	18.1	21.9	18.8	22.6	25.8	32.3	33.0

TABLE C-9 - CASE 10

STEAM GENERATOR DESIGN AND COST INFORMATION

Nameplate Rating, MW	100	200	300	400	500
Refuse Rate, %	58	58	54.5	54.5	54.5
Steam Pressure, psig	1800	1800	2400	2400	2400
Number of Steam Generators (Refuse)	1	2	3	3	4
Number of Turbines	1	1	1	1	1
Steam Generator Cost, 10^6 $	10.2	15.9	22.3	27.5	31.7

TABLE C-10

ITEMS INCLUDED IN STEAM GENERATOR COSTS

Boiler pressure parts

Structural steel for boiler

Platforms and stairways

Fans and motor drives

Water cooled charging hopper

Feed gate

Stoker

Flues and ducts

Refractory insulation and lagging

Tiebacks and backstays

Soot blowers

Normal boiler valves and trim

Hydraulic system for stoker and feed gate

Supplementary oil or gas burners

Economizer

Instruments

Combustion control - positioning type

Siftings removal from precipitators and other hoppers

a. Case 1 - Separate Furnaces, Blended Flue Gas

$$C_{SG} = \left[(14.3 + 33.3\,f_w - 16.2\,f_w^2 + 65\,f_w^3) \left(\frac{P_T}{200} \right)^{N_I} - 5 \right] 10^6$$

and $$N_I = (0.301)^{-1} \times \log \left(\frac{20.13 + 34.14\,f_w + 125.75\,f_w^2 - 98.54\,f_w^3}{14.3 + 33.2\,f_w - 16.2\,f_w^2 + 65\,f_w^3} \right)$$

where: C_{SG} = capital cost of steam generators, \$

f_w = ratio of solid waste heat input to total heat input

P_T = nameplate rating or total plant output power, MW

b. Case 2 - Combined Furnace

Due to the discontinuities in the cost surface, two equations are necessary for this case.

$$\left(C_{SG} \right)_H = \left[(29.3 + 24.08\,f_w - 31.25\,f_w^2 + 54.17\,f_w^3) \left(\frac{P_T}{200} \right)^{(N_{II})_H} - 20 \right] 10^6$$

and $$(N_{II})_H = (0.301)^{-1} \times \log \left(\frac{35.1 + 24.58\,f_w + 91.25\,f_w^2 - 83.3\,f_w^3}{29.3 + 24.08\,f_w - 31.25\,f_w^2 + 54.17\,f_w^3} \right)$$

$$\left(C_{SG} \right)_L = \left[(29.3 + 24.08\,f_w - 31.25\,f_w^2 - 4.17\,f_w^3) \left(\frac{P_T}{200} \right)^{(N_{II})_L} - 20 \right] 10^6$$

and $$(N_{II})_L = (N_{II})_H / 1.7$$

where: $(C_{SG})_H$ = capital cost of steam generators for $200 \leq P_T \leq 500$

$(C_{SG})_L$ = capital cost of steam generators for $P_T < 200$

c. Case 3 - Separately Fired Economizer

$$C_{SG} = \left[(5.27 + 130\, f_w - 271\, f_w^2)\left(\frac{P_T + 50}{350}\right)^{N_{III}}\right] 10^6$$

$$\text{and} \quad N_{III} = (0.196)^{-1} \times \log\left(\frac{17.25 + 72.1\, f_w - 58.5\, f_w^2}{5.27 + 130\, f_w - 271\, f_w^2}\right)$$

d. Case 4 - Separate Fossil Fuel Superheater (Saturated Steam from Refuse-Fired Boiler)

For this case, f_w can assume only one value for each power level; consequently, cost is a function of power only.

$$(C_{SG})_H = 14.56 \times 10^4 (P_T + 50)^{0.898} \quad \text{and } 250 \leq P_T \leq 500$$

$$(C_{SG})_L = 66.5 \times 10^4\, P_T^{0.688} \quad \text{and } P_T < 250$$

e. Case 5 - Separate Fossil Fuel Superheater (Partial Superheat from Refuse-Fired Boiler)

This case is similar to Case 4 in that there is only one value of f_w for each power level.

$$(C_{SG})_H = 22.4 \times 10^4\, P_T^{0.851} \quad \text{and } 300 \leq P_T \leq 500$$

$$(C_{SG})_L = 98 \times 10^4\, P_T^{0.591} \quad \text{and } P_T < 300$$

f. Case 6 - Suspension Fired Steam Generator

$$(C_{SG})_L = \left\{(1.12 - .005\, f_w + .31 f_w^2 \exp\left[N_{VI}(P_T - 200)\right] - 1\right\} 10^8$$

$$\text{and} \quad N_{VI} = 0.005 \times \ln\left(\frac{1.14 + 1.38\, f_w + 1.14\, f_w^2}{1.12 - .005\, f_w + .31\, f_w^2}\right)$$

$$(C_{SG})_H = \left\{(1.12 - .005\, f_w + .31\, f_w^2 \exp\left[\frac{N_{VI}}{1.3}(P_T - 200)\right] - 1\right\} 10^8$$

where: $(C_{SG})_H$ = capital cost of steam generators when $P_T \geq 450$

$(C_{SG})_L$ = capital cost of steam generators when $P_T < 450$

g. Case 7 - Spreader Stoker

The steam generator cost for this case is the same as for Case 6.

h. Case 8 - Slagging Furnace

The capital cost of steam generators for the slagging furnace is the same as for Case 2.

i. Case 9 - Combined-Fired Arch Furnace

A preliminary analysis of the cost data for this case showed that it would not be economically competitive with other cases. Therefore, an equation form was not derived for this case.

j. Case 10 - Refuse-Fired Arch Furnace and Separate Coal-Fired Superheater

$$(C_{SG})_H = 442 \times 10^3 \, P_T^{0.689} \quad \text{and} \quad P_T > 250$$

$$(C_{SG})_L = 545 \times 10^3 \, P_T^{0.637} \quad \text{and} \quad P_T \leq 250$$

4. Auxiliary Boiler Equipment

The basic capital costs for boiler feed water treatment pumps, piping, coal and residue handling, and stacks, were also fit to equation form. The costs of these equipments were adjusted for the number of steam generators required, with the exception of piping costs which were adjusted for the number of turbines required in each of the designs considered. Since the amount of furnace residue and stack gas are dependent on the relative quantities of solid waste and fossil fuel, the costs are expressed as functions of the waste and coal flow rates. The equations take the following form and are illustrated in Figures C-3 through C-8.

$$C_W = 2.21 \times 10^3 P_T$$

$$C_{PE} = 1.11 \times 10^4 \left(\frac{P_T}{(N_s)_{i,j}}\right)^{0.73} (N_s)_{i,j}$$

$$C_P = 5.9 \times 10^3 \left(\frac{P_T}{(N_T)_{i,j}}\right)^{1.1} (N_T)_{i,j}$$

$$C_{CO} = 1.8 \times 10^4 \left[P_T \left(1 - \frac{f_w \; \eta_{SGW}}{\eta_{SGF}(1 - f_w) + \eta_{SGW} \, f_w}\right)\right]^{0.74}$$

$$C_R = 3.66 \times 10^4 \left(\frac{A}{(N_s)_{i,j}}\right)^{0.858} (N_s)_{i,j}$$

and $$A = 1.18 \times 10^{-3} W_f + 8.3 \times 10^{-3} W_w$$

$$C_S = (934 \, W_f + 500 \, W_w) \, 0.151$$

where: C_W = capital cost of boiler water treatment equipment, \$ (see Figure C-3)

C_{PE} = capital cost of pumps, \$ (see Figure C-4)

C_P = capital cost of piping, \$ (see Figure C-5)

C_{CO} = capital cost of coal handling equipment, \$ (see Figure C-6)

C_R = capital cost of residue handling equipment, \$ (see Figure C-7)

A = furnace residue, tph

η_{SGW} = boiler efficiency for refuse firing

η_{SGF} = boiler efficiency for coal firing

W_f = coal rate, tpd

W_w = solid waste rate, tpd

C_S = capital cost of stacks, \$ (see Figure C-8)

$(N_s)_{i,j}$ = number of steam generators in the plant at power level i and waste fraction j

$(N_T)_{i,j}$ = number of turbines in the plant at power level i and waste fraction j

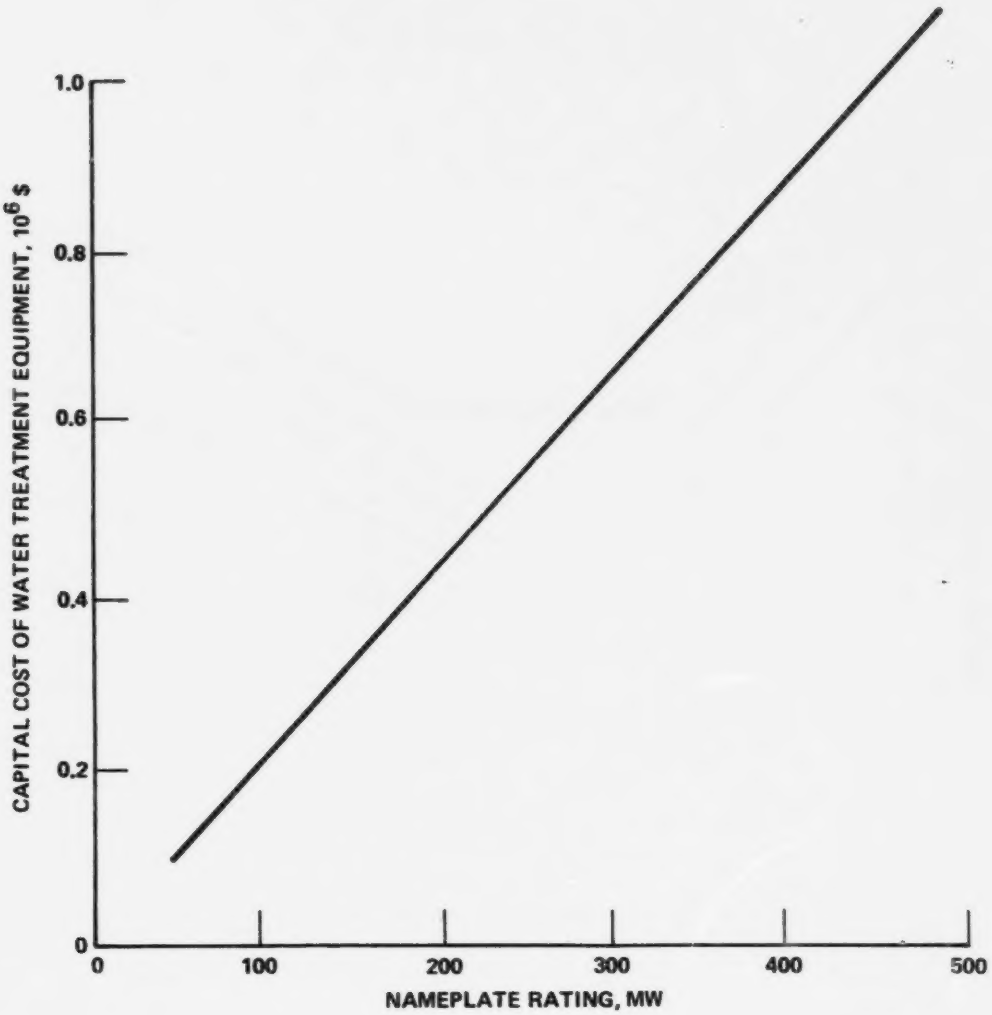


FIGURE C-3. CAPITAL COST OF WATER TREATMENT EQUIPMENT

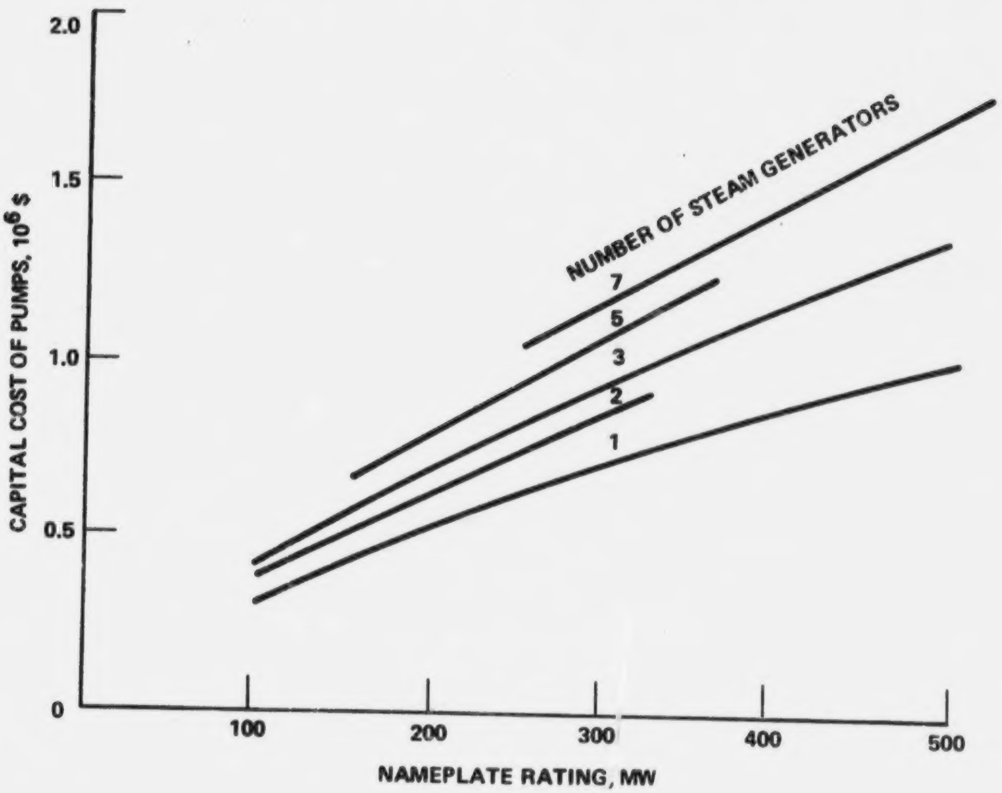


FIGURE C-4. CAPITAL COST OF PUMPS

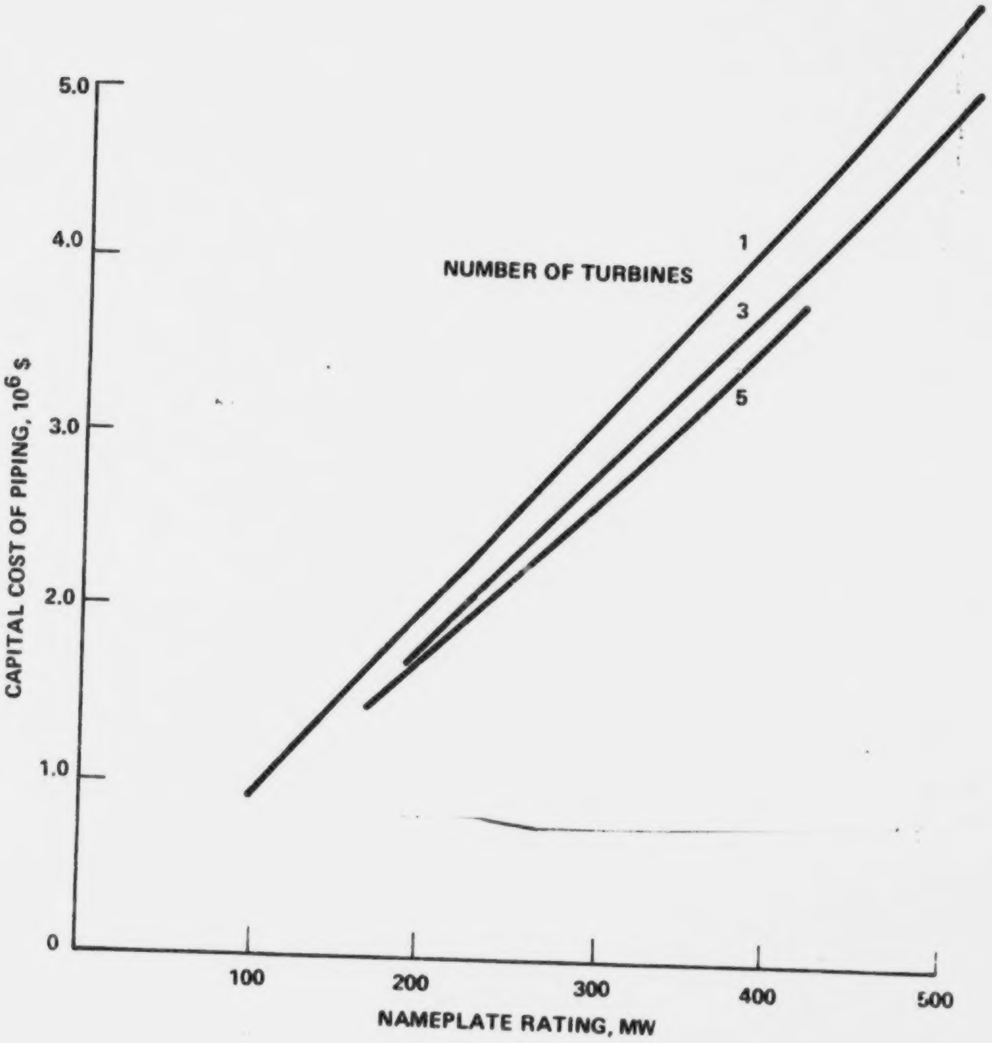


FIGURE C-5. CAPITAL COST OF PIPING

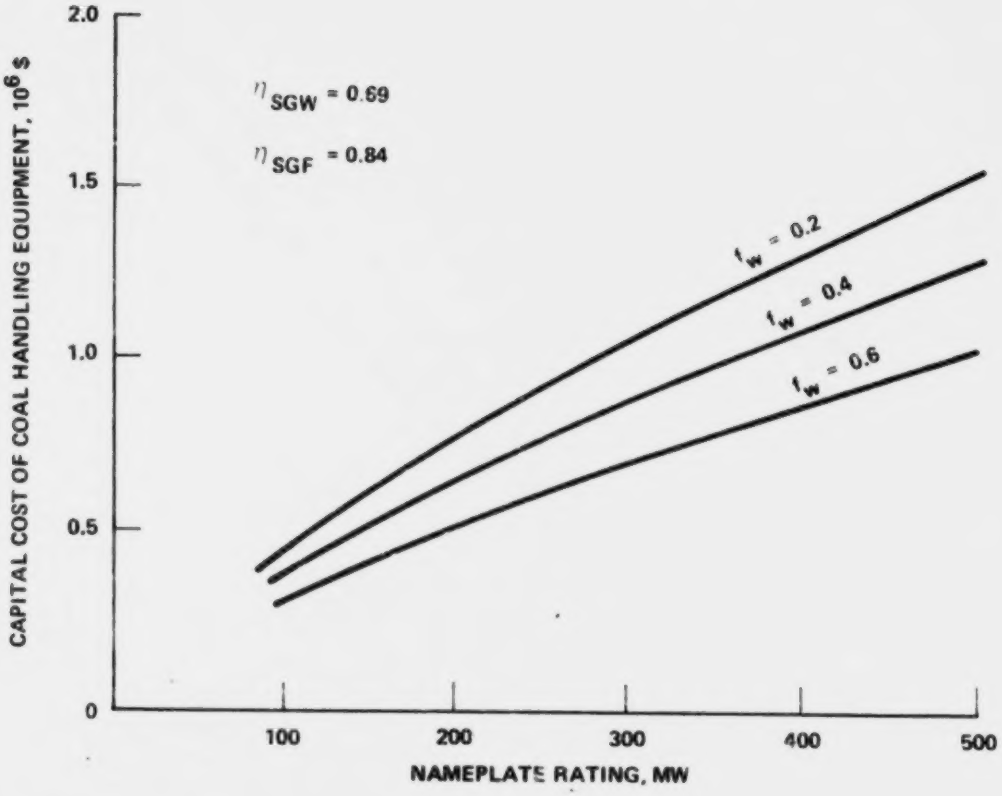


FIGURE C-6. CAPITAL COST OF COAL HANDLING EQUIPMENT

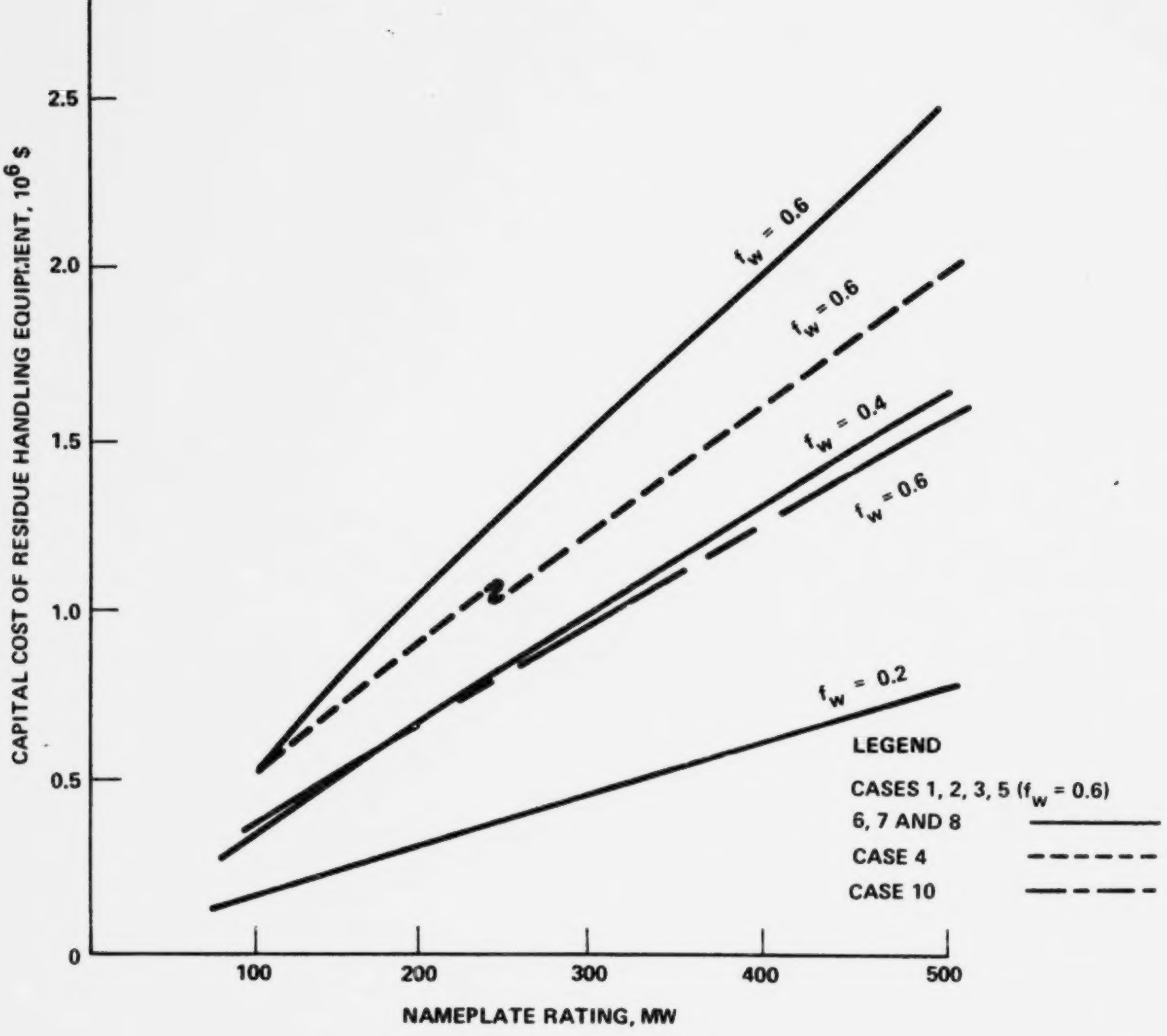


FIGURE C-7. CAPITAL COST OF RESIDUE HANDLING EQUIPMENT

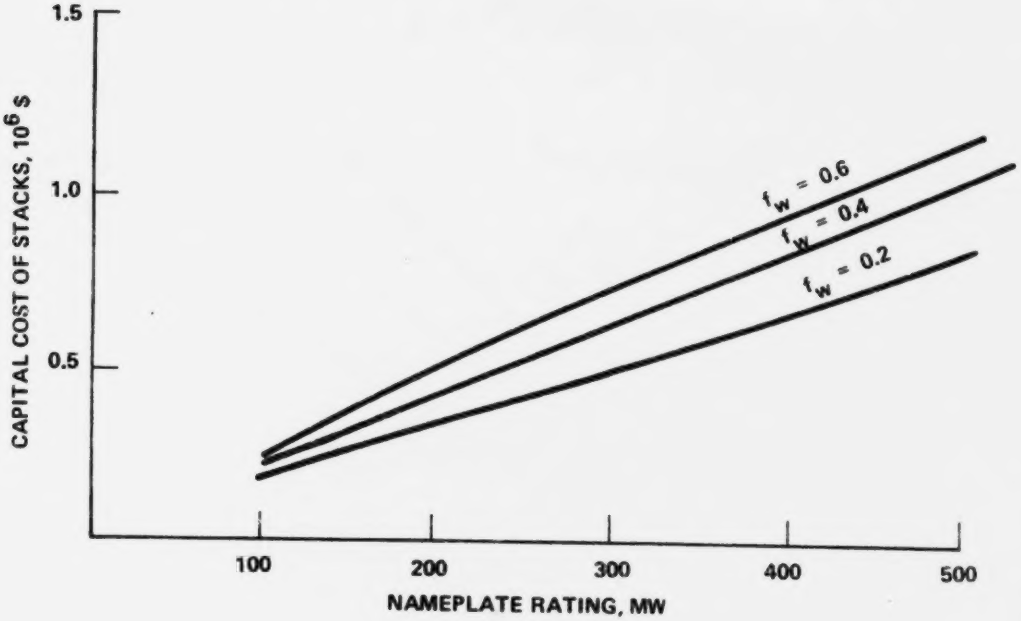


FIGURE C-8. CAPITAL COST OF STACKS

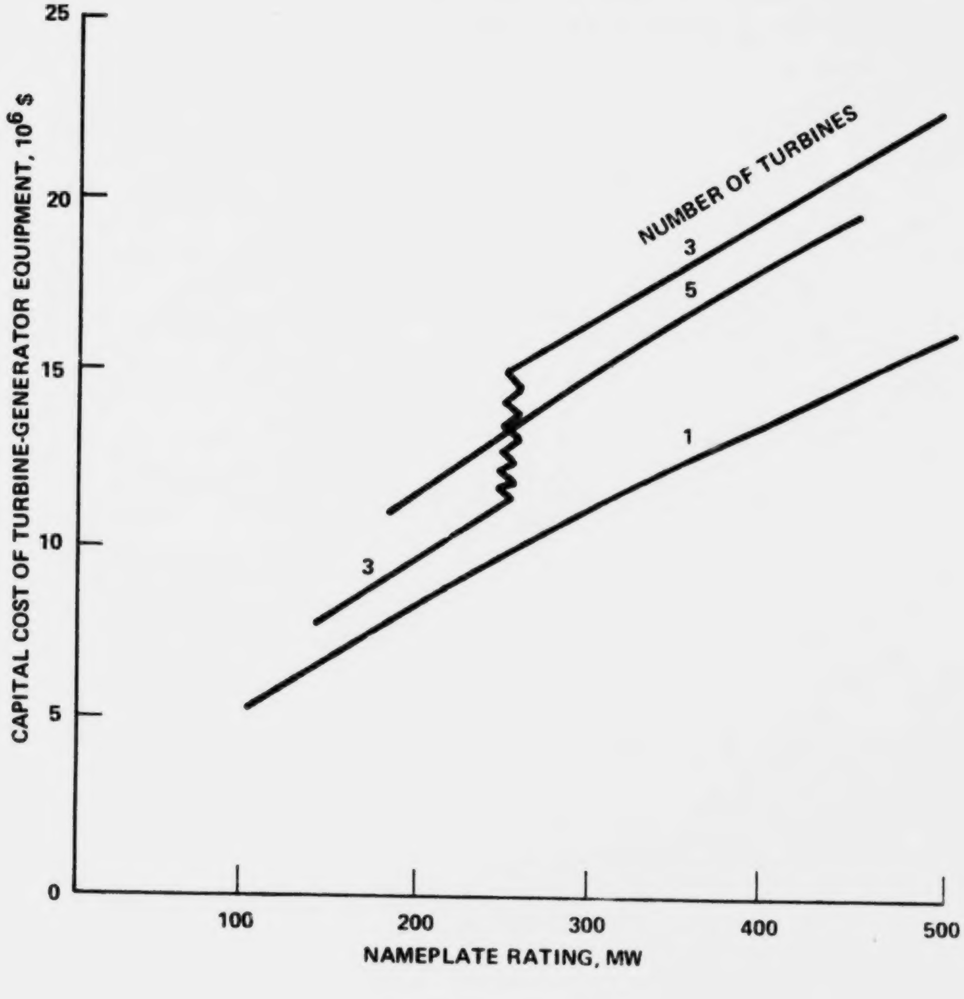


FIGURE C-9. CAPITAL COST OF TURBINE-GENERATOR EQUIPMENT

5. Turbine-Generator Equipment

The capital cost of the turbine-generator equipment includes the cost of the turbine-generator assembly and the condenser and associated cooling equipment. Due to the changing steam conditions, two equations are necessary to fit the data for these costs. The costs are then adjusted to account for multiple turbines. Figure C-9 shows the total capital cost for turbine-generator equipment as a function of power.

$$\left.\begin{aligned} (C_T)_H &= 14.04 \times 10^4 \left(\frac{P_T}{(N_T)_{i,j}}\right)^{0.725} (N_T)_{i,j} \\ (C_C)_H &= 7.36 \times 10^3 \left(\frac{P_T}{(N_T)_{i,j}}\right)^{0.886} (N_T)_{i,j} \\ (C_{CE})_H &= 2.17 \times 10^5 \left(\frac{P_T}{(N_T)_{i,j}}\right)^{0.352} (N_T)_{i,j} \end{aligned}\right\} 85 \le \frac{P_T}{(N_T)_{i,j}} \le 500$$

$$\left.\begin{aligned} (CT)_L &= (C_T)_H \; 0.79 \\ (C_C)_L &= (C_T)_H \; 0.79 \\ (C_{CE})_L &= (C_T)_H \; 0.79 \end{aligned}\right\} \frac{P_T}{(N_T)_{i,j}} < 85$$

where

C_T = cost of turbine generator, \$

C_C = cost of condenser, \$

C_{CE} = cost of cooling equipment, \$

6. Accessory Electrical Equipment

This cost element is the summation of electrical control board, switchgear, conduit and cable, inverter, and an intercom system.

$$C_E = 2.83 \times 10^4 \, P_T^{0.771}$$

7. Miscellaneous Power Plant Equipment

This cost element consists of the cost of cranes, for handling generator room equipment (not refuse), and miscellaneous equipment such as air compressors, miscellaneous machinery, and fire protection.

$$C_{PCR} = 2.3 \times 10^3 \, P_T^{0.86}$$

$$C_M = 4.63 \times 10^4 \, P_T^{0.24}$$

where: C_{PCR} = capital cost of power plant cranes, \$

C_M = capital cost of miscellaneous equipment, \$

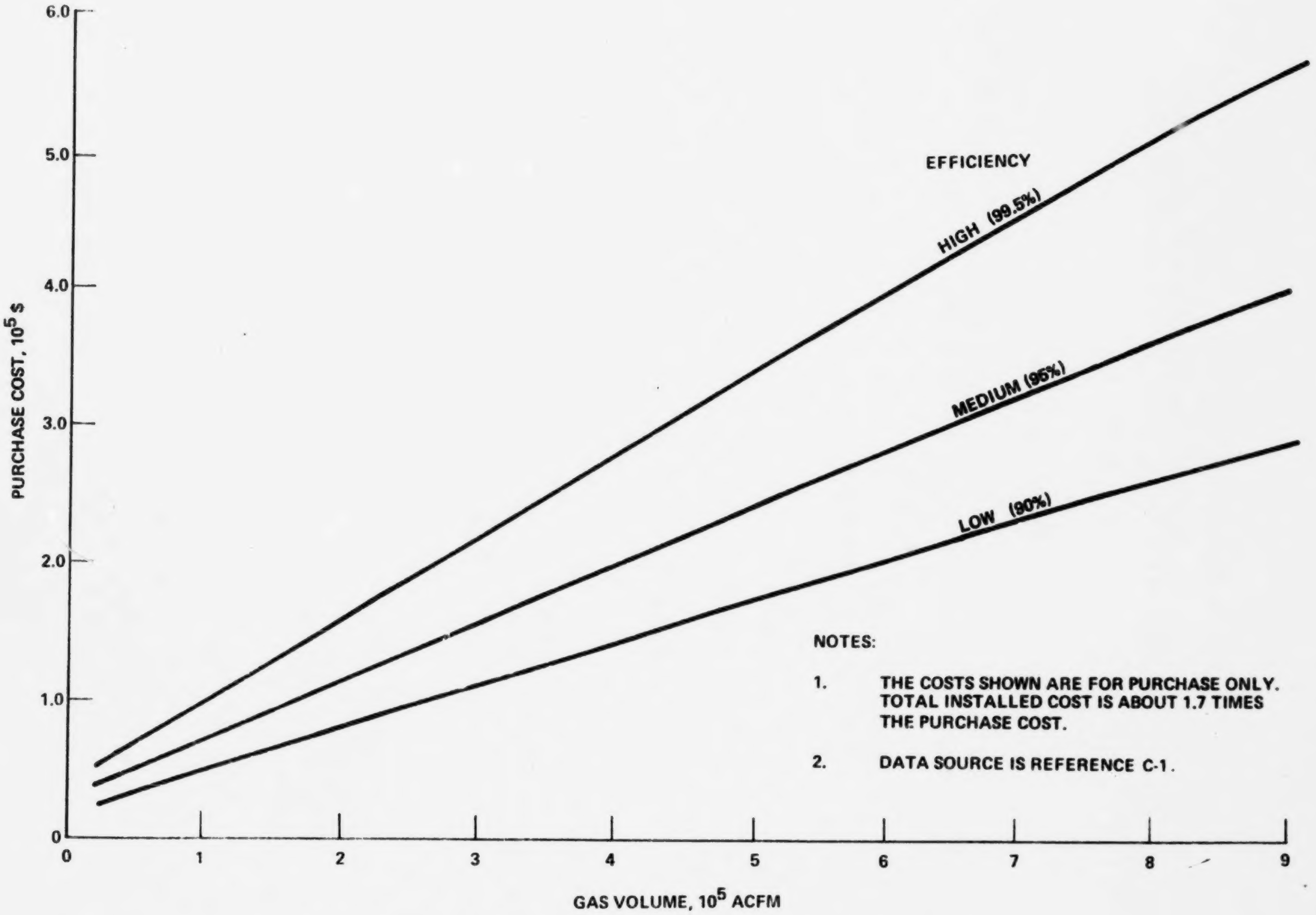
8. Air Pollution Control Equipment

Two potential air pollutants are considered in this cost model: particulates and SO_2. The cost of air pollution control equipment is a function of the flue gas flow rate, efficiency, and the type of device being used. In this model an electrostatic precipitator is used for control of particulates in flue gases low in SO_2 (i.e., from furnaces firing refuse only) and a wet scrubber is utilized for both particulate matter and SO_2 control when flue gas arises wholly or partly from coal combustion.

a. Electrostatic Precipitator

Data from two sources were used to obtain the capital cost of electrostatic precipitators. Data extracted from Reference C-1 (reproduced as Figure C-10) were used to scale costs as a function of efficiency while the additional cost data shown as Figure C-11 were used as the reference point. The applicable cost equation is as follows:

$$C_{IP} = \left[\eta_p^{10.1}\left(0.812\,V + 60.4 \times 10^3\right) + 0.247\,V + 12.7 \times 10^3\right] \Big/ \left(\frac{V}{2.35 \times 10^5}\right)^{0.15}$$

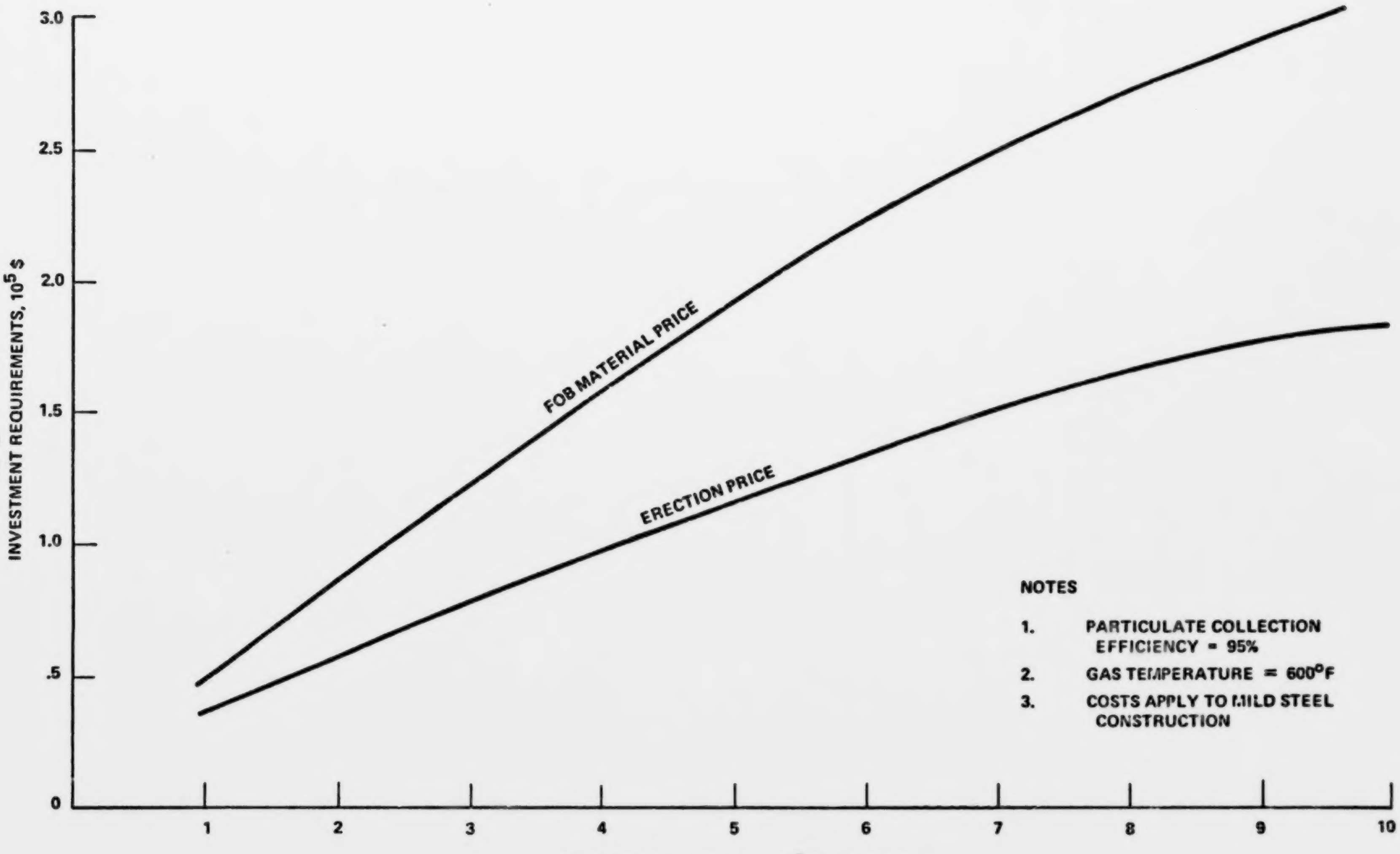


NOTES:

1. THE COSTS SHOWN ARE FOR PURCHASE ONLY. TOTAL INSTALLED COST IS ABOUT 1.7 TIMES THE PURCHASE COST.

2. DATA SOURCE IS REFERENCE C-1.

FIGURE C-10. PURCHASE COST OF ELECTROSTATIC PRECIPITATORS



NOTES

1. PARTICULATE COLLECTION EFFICIENCY = 95%
2. GAS TEMPERATURE = 600°F
3. COSTS APPLY TO MILD STEEL CONSTRUCTION

FIGURE C-11. COSTS OF ELECTROSTATIC PRECIPITATORS FOR MUNICIPAL REFUSE INCINERATORS (REFRACTORY FURNACES) where: C_{IP} = capital cost of an electrostatic precipitator, \$

η_p = electrostatic precipitator efficiency

V = volumetric flow rate, ACFM

b. Wet Scrubber

As pointed out in the systems analysis developed in Section III, B, a limestone wet scrubber was selected for SO_2 removal. The installed cost of a wet limestone scrubber system is determined from the sum of the costs of equipment for injecting limestone into the scrubber liquor and removing calcium sulfate therefrom, of reheating the cleaned gas to give plume-free stack operation, and of the wet scrubber. Using the data shown in Table C-11 (obtained from Ref. C-2), the following equations were determined.

$$C_{INJ} = 2.75 \times 10^4 \, P_F^{0.69}$$

where: C_{INJ} = cost of limestone handling equipment, \$

P_F = plant power derived from fossil fuel, MW

$$C_{RH} = 1.14 \times 10^4 \, P_T^{0.8}$$

where: C_{RH} = cost of gas reheater, \$

Data were extracted from Reference C-1 to obtain the capital cost of wet scrubbers. These data are reproduced in Figure C-12. The applicable cost equation is as follows:

$$C_{IWS} = (1.06 \times 10^{-2} \, V + 131.6) \exp (4.25 \, \eta_w)$$

where: C_{IWS} = capital cost of wet scrubber, \$

η = wet scrubber efficiency

9. Waste Handling Equipment

a. Weigh and Receiving Stations

The capital cost of waste handling equipment consists of the cost of receiving and storage, cost of scales, and the cost of shredders. The cost of the receiving and storage area were determined from a cost study of a conceptual design of a live bottom pit system such as discussed in Section III, B. The cost data are shown in Table C-12. The equation developed for receiving and storage facility cost (C_{ST}) is:

TABLE C-11

INSTALLED COST OF LIMESTONE SCRUBBER INJECTION EQUIPMENT, EXCLUDING WET SCRUBBER AND REHEAT SYSTEM*

	200 MW	1000 MW
Total Direct Cost	$ 847,000	$2,561,000
Engineering @ 10%	84,700	256,100
Contractor Fees @ 15%	127,000	385,000
Contingency @ 10%	84,700	256,100
Total Investment	$1,143,400	$3,467,200

Installed Cost of Gas Reheat System

	200 MW	1000 MW
Total Direct Cost	$ 585,000	$2,125,000
Engineering @ 10%	58,500	212,500
Contractor Fees @ 15%	87,700	319,000
Contingency @ 10%	58,500	212,500
Total Investment	$ 789,700	$2,869,000

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*From Reference C-2.

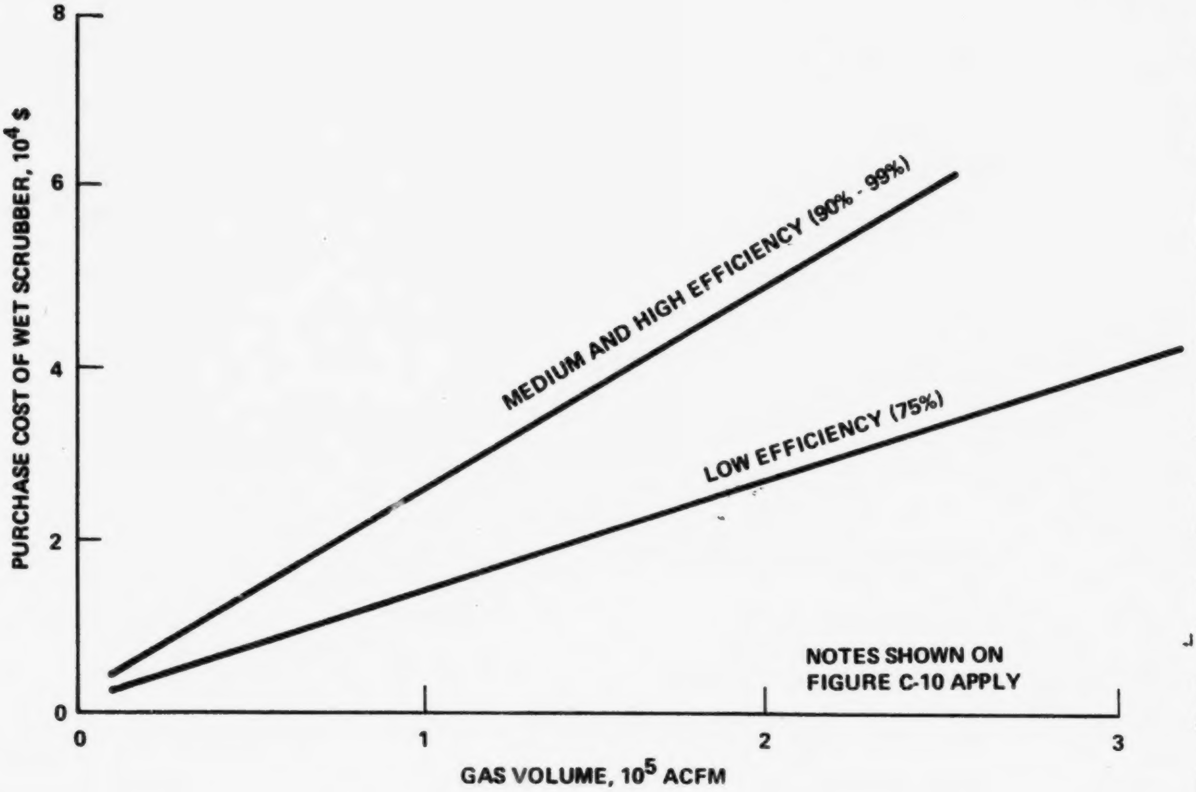


FIGURE C-12. PURCHASE COST OF WET SCRUBBERS

TABLE C-12

COST ESTIMATE SUMMARY OF RECEIVING AND STORAGE FACILITIES AND EQUIPMENT

2000 TPD	Low Profile	High Profile
Conveyors	$ 459,000	$ 496,600
Receiving Area	188,000	188,000
Storage Pits	685,000	572,000
Total	$1,332,000	$1,256,000

8000 TPD	Low Profile	High Profile
Conveyors	$1,561,000	$1,731,000
Receiving Area	697,000	697,000
Storage Pits	1,949,000	1,547,000
Total	$4,207,000	$3,975,000

NOTE: Above summary costs include a 30% contingency allowance for small plants and a 30% x 0.67 or 20% contingency allowance for large plants (0.67 size factor).

$$C_{ST} = 2.08 \times 10^3\ W_w^{0.84}$$

Weighing and receiving of solid waste at a disposal or processing site represents a queueing problem. To ascertain how many weighing stations and receiving stations should be provided for plants of various sizes, it is necessary to make a trade-off between the cost of providing additional stations and the cost of trucks waiting in line. Trade-off studies for this queueing problem were made by conducting several simulation runs using IBM General Purpose Simulation System/360 (GPSS/360) language.

GPSS permits the simulation of dynamic systems given in this particular case, the distribution of truck arrivals, weighing time, and receiving time, and the number of stations being considered. The output of the simulation is the amount of time spent queueing. Using the queue time and the costs associated with weigh stations, dumping stations, and trucks, the combination that will provide a minimum cost system can be determined.

The assumptions and input data used in the simulation model were as follows:

- Truck capacity is 25 yd^3.
- The specific weight of refuse is 600 lb/yd^3 compacted in the truck.
- There are two peak truck arrival periods per day, each lasting one hour, and 80% of the total waste is delivered during these two peak periods.
- Weighing time is equidistributed at 24 ± 2 seconds.
- Dumping time is equidistributed at 155 ± 40 seconds.
- Truck arrivals during the peak period are Poisson distributed.

The unit costs of weigh stations, receiving stations, and trucks were estimated to be $6.00, $1.63, and $21.75 per hour, respectively. Using these costs and the output of the GPSS/360 model, the total cost in dollars per ton of solid waste, for weigh stations, receiving stations, and truck delay, were calculated. Figure C-13 shows the results

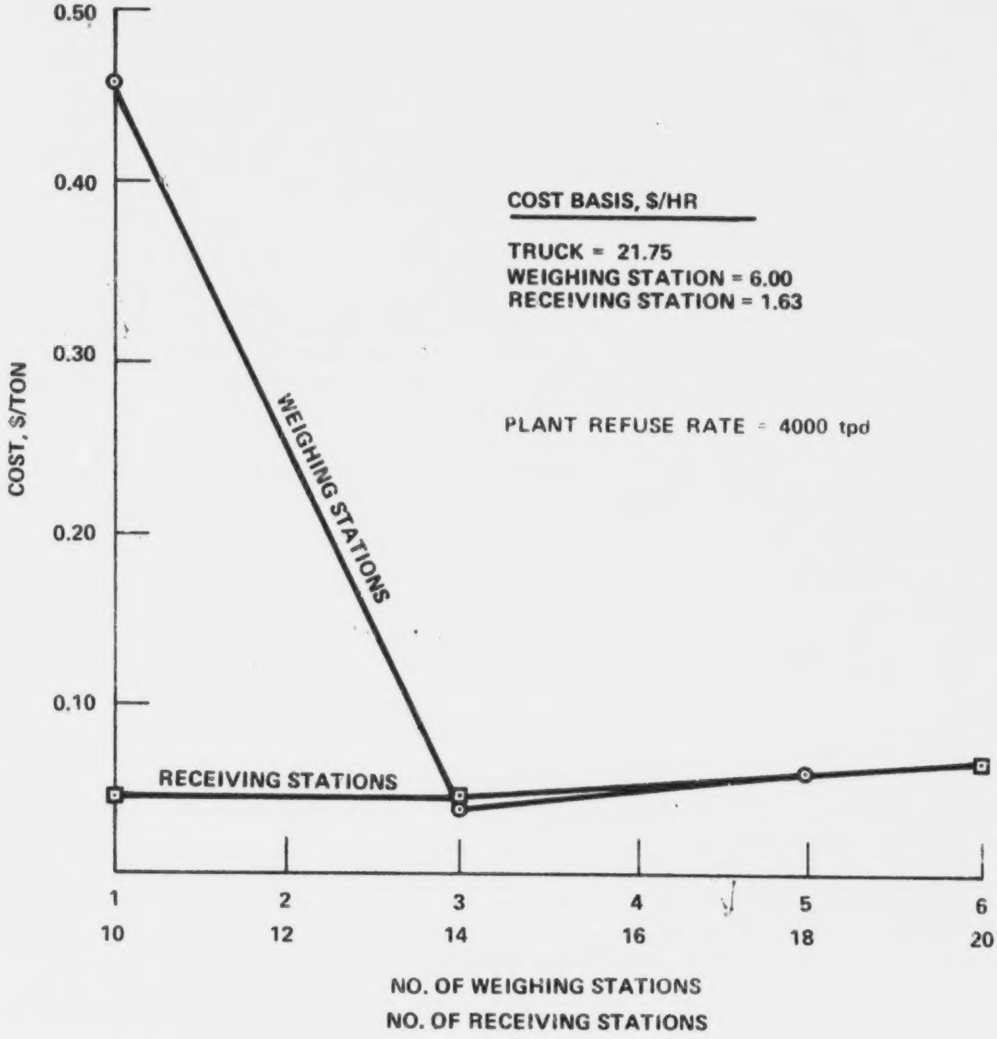


FIGURE C-13. TRUCK DELAY AND STATION COSTS for the case of 4000 tpd operation, including the cost of truck delay. The table below summarizes the optimum number of weigh stations and receiving stations for various waste loads.

OPTIMUM NUMBER OF WEIGH SCALES AND RECEIVING STATIONS

Load, tpd	Weigh Scales, No.	Receiving Stations, No.
1000	1	3
2000	1	6
4000	3	12
6000	4	16

It should be noted that once some minimum number of stations are provided, the cost is not very sensitive to the further addition of stations. More specifically, Figure C-13 shows that increasing the number of weigh stations beyond 3 or the number of receiving stations beyond 14 adds very little to cost of the 4000 tpd case.

The cost of scales is estimated to be $16,000 for a semi-automatic device. This yields a capital cost of:

$$C_{SCAL} = 16,000\ N_{SCAL}$$

where: N_{SCAL} = number of weighing stations required as determined by the queueing study

b. Shredding Equipment

Three different conditions for shredding the waste are considered in this model; namely, a 4-inch nominal top-size product and all waste is shredded, a 2-inch product and all waste is shredded, and a 4-inch product but only bulky wastes are shredded. It is assumed, on a conservative basis, that 2-inch shredding equipment will cost approximately twice as much as 4-inch shredding equipment. The equations developed for each shredding condition are presented below:

- 4-inch product and all waste is shredded

$$C_{SRED} = 1420\ W_w + 340 \times 10^3$$

- 2-inch product and all waste is shredded

$$C_{SRED} = 2840\ W_w + 680 \times 10^3$$

- 4-inch product and only bulky waste is shredded

$$C_{SRED} = 58.5\ W_w$$

10. Engineering and Construction Supervision

It was determined that the cost of engineering and construction supervision varies from 4 to 5% of the total capital cost over the 200 to 400 MW range. Using these percentages, an exponential scaling equation was developed to predict the cost of engineering and inspection.

$$C_{EI} = 0.313\ P_T^{-0.343} \times \text{(total capital cost)}$$

B. ANNUAL CAPITAL COSTS

The annual capital costs are determined by annualizing the capital cost, using an appropriate capital recovery factor, and then adding to this a value to represent the annual cost of insurance and taxes. The model assumes that the power plant is a privately owned regulated public utility that is subject to all applicable federal, state, and local taxes and is allowed to earn a "fair rate of return."

1. Amortization

The capital recovery factor represents the annual percentage that is required to amortize the capital debt at the regulated rate of return. In equation form:

$$\text{CRF}\ (r,\ N) = \frac{r(1+r)^N}{(1+r)^N - 1}$$

where CRF (r, N) = annualization rate for an equipment with a useful life of N years at a return of r percent

In this report, a 7% rate of return has been assumed and a value of N (Equipment Life, see Table C-1) has been given to each major piece of equipment.

2. Federal Taxes

Since the profits from a regulated public utility are ideally a function of the capital investiment, the allowance for federal corporate income tax can also be computed as a percentage of the capital investment using the following formula:

$$TAX = \frac{e}{1 - e} (r - ic) \left[s + (1 - s) (1 - \frac{gf(r, N)}{N} \right]$$

where TAX = ratio of equivalent annual tax to first cost

e = federal tax rate

r = rate of return

i = interest rate on debt

c = debt ratio (total debts to total assets)

s = salvage value

and $$gf(r, N) = \frac{1}{r} - \frac{N}{r} \left[\frac{r}{(1 + r)^N - 1} \right]$$

For example, if:

r = 7%

i = 6%

e = 55%

c = 50%

s = 0

then the allowance for federal income is found to be 3.1% of the capital cost of the plant.

3. Insurance and State and Local Taxes

Insurance has been estimated to cost 0.25% of the plant costs; data from Reference C-3 indicate that state and local taxes for regulated utilities average 1.9% of the capital costs.

C. OPERATION AND MAINTENANCE

1. Basic O & M Costs

The operation and maintenance costs for the combined firing plant consist of the operating labor shown in Table C-13; the maintenance costs for the power plant, the coal costs, plus additional operation and maintenance costs for shredders and air pollution control equipment.

TABLE C-13

LABOR REQUIREMENT AND COST

Categories	Rate Dollars/Yr	Shift 1	Shift 2	Shift 3	Shift 4
Superintendent	20,000	1			
Plant Engineer	17,000	1			
Shift Engineer	15,000	1	1	1	1
Turbine Operator	12,000	1	1	1	1
Turbine Room Attendant	10,000	1	1	1	1
Control Room Attendant	10,000	1	1	1	1
Incinerator Operator	8,000	0.5/unit	0.5/unit	0.5/unit	0.5/unit
Boiler Operator	8,000	0.25/unit	0.25/unit	0.25/unit	0.25/unit
Tipping Floor Attendant	9,000	$\frac{1}{1000 \text{ tons/day}}$			
Cleanup Labor	6,000	$\frac{0.6 \text{ men}}{1000 \text{ tons/day}}$			
Ash Cleaning Labor	6,000	$\frac{1}{1000 \text{ ton/day ash}}$	$\frac{1}{1000 \text{ ton/day ash}}$	$\frac{1}{1000 \text{ ton/day ash}}$	$\frac{1}{1000 \text{ ton/day ash}}$
Maintenance Mechanic	10,000	0.25/unit	0.25/unit	0.25/unit	0.25/unit
Electrician	14,000	1			
Shredder Operator	9,000	$\frac{1}{1000 \text{ tons/day}}$			
Conveyor Operator	8,000	0.25/unit	0.25/unit	0.25/unit	0.25/unit
Clerical	6,000	2			
Instrument Technician	8,000	1	1	1	1

NOTE: The cost of labor is increased by 25% over the tabular costs to account for fringe benefits.

The annual plant maintenance costs (with the exception of the following items) are estimated to be 10% of the capital costs. The cost of the coal can be derived from the following equation:

$$C_{COAL} = 0.73\, W_F H_F C_U L_F$$

where C_{COAL} = cost of coal, \$/yr

W_F = coal rate, tpd

H_F = coal heating value, Btu/lb

C_U = unit cost of coal, \$/10^6 Btu's

L_F = plant factor

2. Shredding O & M Costs

Data from Reference C-4 indicate that the operation and maintenance cost for shredding (excluding operating labor) will vary from approximately \$1.00 to \$0.25 per ton over a range of 10 to 90 tph. Using this data, an equation was developed for the 4-in. shredder where only bulky wastes are handled. It is assumed that bulky wastes are 5% of the total.

$$C_{MSHRD} = 5.8 \times 10^3\, (.05\, W_w)^{0.368}$$

where C_{MSHRD} = operation and maintenance cost of a shredder in the 10 to 90 tpd range, \$/yr

W_w = waste load, tpd

For cases where all the waste is ground to a 4-in. top-size, several shredders of the size range noted above are required. To obtain costs for this case, the single shredder equation above was used and multiplied by the number of shredders required. The resulting cost data were then fit to the following equation.

$$C_{MSHRD} = 456\, W_w^{\,0.845}$$

For the case of shredding to 2-in. top size, it was assumed that the operation and maintenance cost for the 4-in. top size would be doubled. Figure C-14 shows operation and maintenance cost for shredding as generated from the above equations.

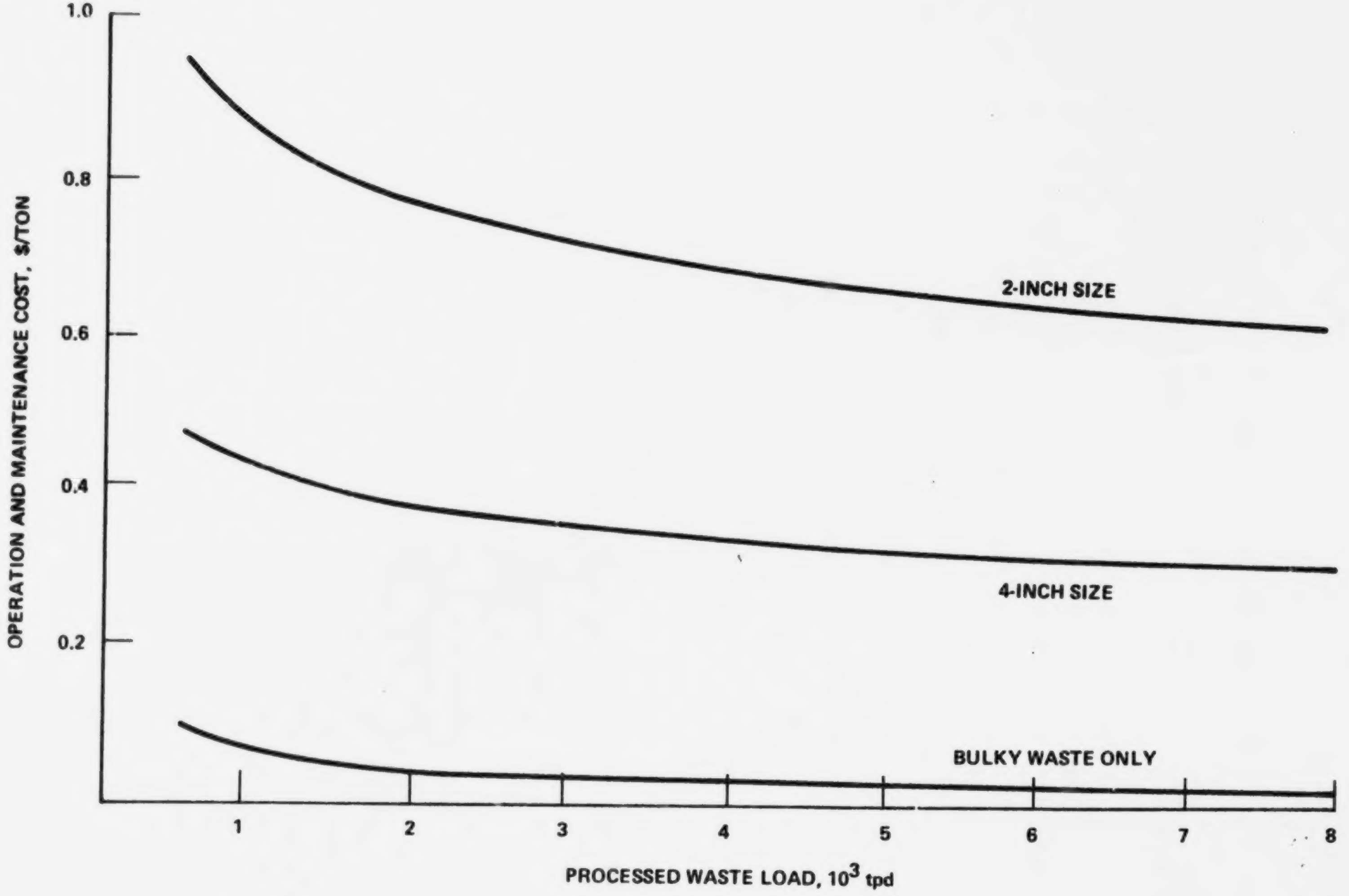


FIGURE C-14. OPERATION AND MAINTENANCE COST OF SHREDDERS

3. Air Pollution Control O & M Costs

An equation for the operation and maintenance cost of electrostatic precipitators is given in Reference C-1 as

$$G = S\,(J\,H\,K + M)$$

where G = operation and maintenance cost, \$/yr

S = design capacity, ACFM

J = power required, kw/ACFM

H = annual operating time, hrs/yr

K = power cost, \$/kw-hr

M = maintenance cost, \$/ACFM-yr

Reference C-1 gives typical values for J and M of 0.26×10^{-3} kw/ACFM and \$0.02/ACFM-yr, respectively. Using 8760 hrs/yr and a power cost of 0.6 mills per kw-hr, the operation and maintenance cost of electrostatic precipitators becomes

$$G = 0.024\,(\text{ACFM})$$

The results of this equation are plotted in Figure C-15.

The following equation for the operation and maintenance cost of wet scrubbers is also given in Reference C-1:

$$G = S\left[0.7457\,HK\left(\frac{P}{6356E} + \frac{Qg}{1722F} + \frac{Qh}{3960F}\right) + WHL + M\right]$$

where:

Term	Definition	Typical Value (Ref. C-1)
P =	pressure drop across fan, in. of water	10
E =	fan efficiency in decimal form	0.6
Q =	liquor circulation, gal/ACFM	0.008
g =	liquor pressure at the collector, psig	13
F =	pump efficiency in decimal form	0.5

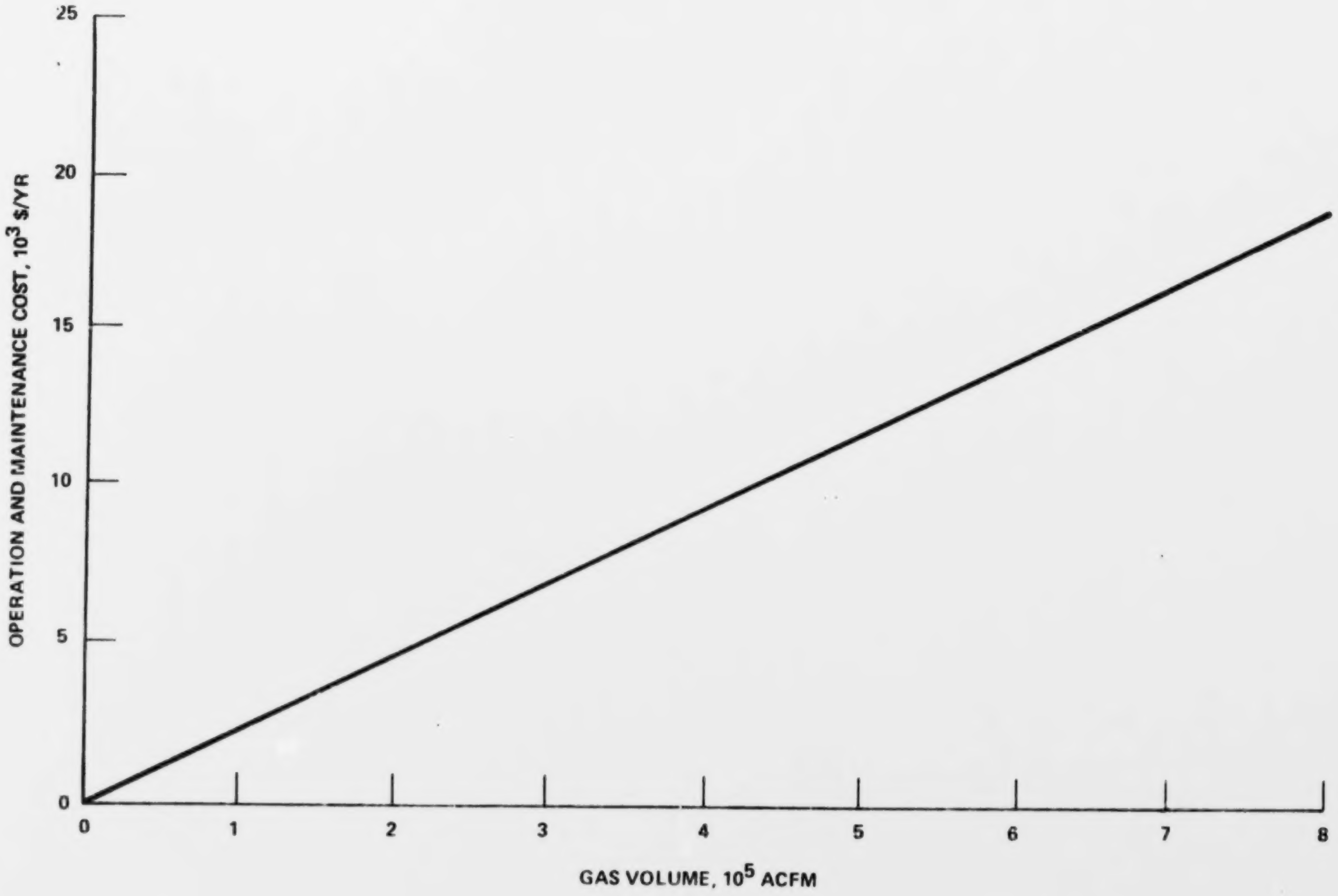


FIGURE C-15. OPERATION AND MAINTENANCE COST OF ELECTROSTATIC PRECIPITATORS

Term		Definition	Typical Value (Ref. C-1)
h	=	physical height liquor is pumped, ft	30
W	=	make-up liquor consumption, gal. /hr ACFM	0.0005
L	=	liquor cost, \$/gal.	0.5×10^{-3}
M	=	(see previous equation)	0.04
K	=	(see previous equation)	0.006
H	=	(see previous equation)	8760

Introducing the Reference C-1 values into the equation for operation and maintenance of wet scrubbers simplifies it to the following:

$$G = 0.15 \text{ (ACFM)}$$

The results of this equation are shown in Figure C-16.

The O & M costs of wet scrubbers given above do not include costs incurred in the handling of limestone and calcium sulfate. Therefore, an additional cost is necessary. From Reference C-2, the O & M costs associated with limestone scrubbing varies from \$373,000 to \$1,432,000 per year over the range of 200 MW to 1000 MW plant sizes. These data were used to develop the following equation for the O & M costs, C_{MSO}, of the ancillary limestone equipment.

$$C_{MSO} = 1.32 \times 10^3 \, P_F + 1.1 \times 10^5$$

where P_F = power derived from fossil fuel, MW

4. Residue Disposal Costs

The cost of power plant residue disposal is calculated by assuming 76 cents per ton to place the residue in a landfill plus 20 cents per ton-mile transportation. Included as residue is 5% of the incoming waste load.

$$C_{DIS} = (0.05 \, W_w + AL_F)(730 \, C_{MILE} \, D + 365 \, C_L)$$

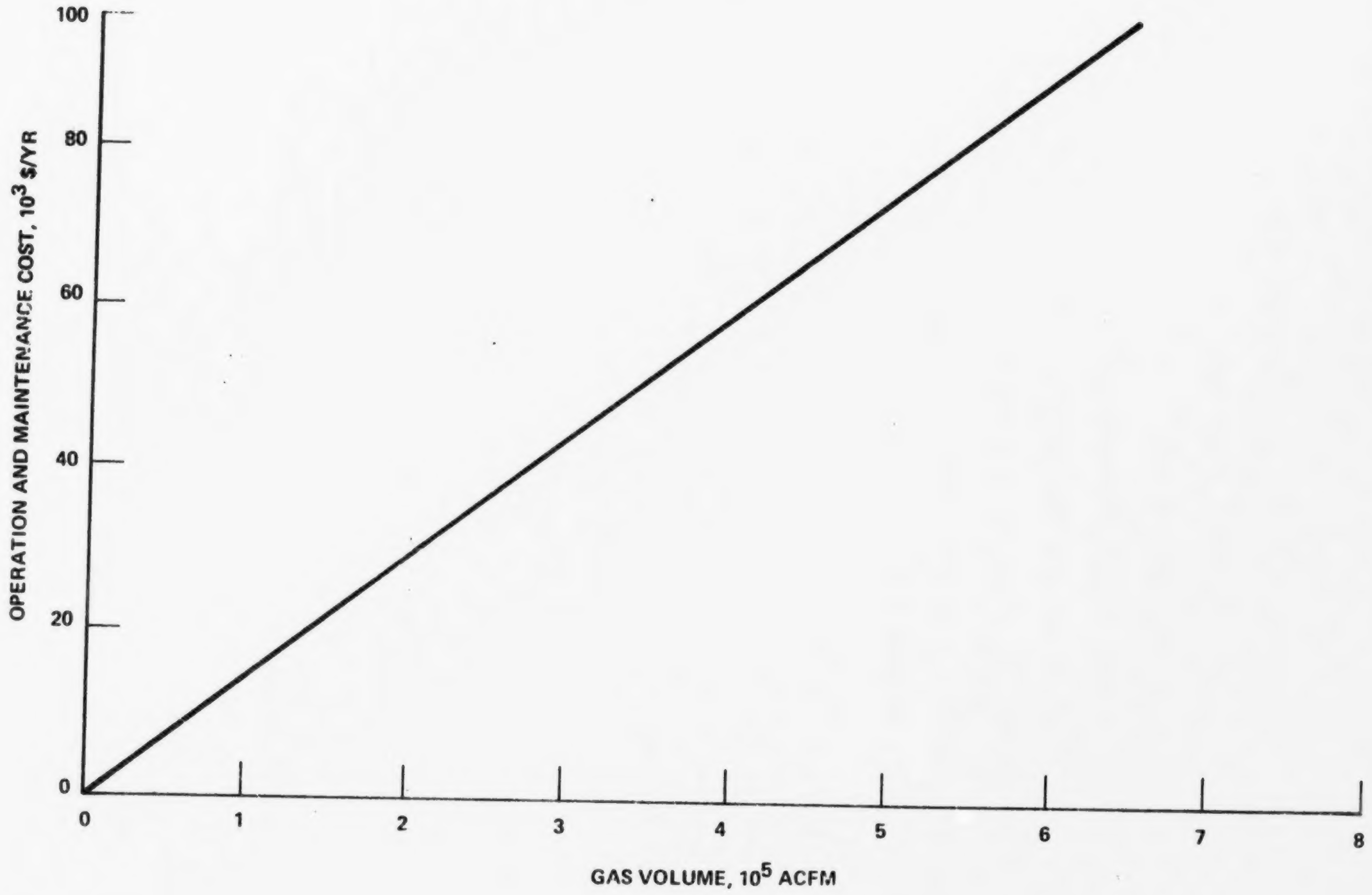


FIGURE C-16. OPERATION AND MAINTENANCE COST OF WET SCRUBBERS where C_{DIS} = cost of residue disposal, \$/yr

A = amount of ash, tpd

L_F = plant factor

D = haul distance, miles

C_L = unit cost of landfill, \$/ton

C_{MILE} = unit cost of transportation, \$/ton-mile

W_w = processed waste load, tpd

D. POWER GENERATION CREDIT

The amount of credit for power generated is computed by estimating the cost of power in a conventional coal burning power plant with air pollution control. The annualization factors used for this estimate are the same as those that were used for the waste-fossil fuel power plant. The model is summarized in Figure C-17, which shows the cost of power as a function of plant capacity and fuel cost. Equations for the capital cost of equipment, annual capital costs, operation and maintenance, and residue disposal and coal costs are tabulated in Table C-14.

E. NET SOLID WASTE DISPOSAL CHARGE

The net solid waste disposal charge or "Disposal Cost", is the cost of disposing of a ton of refuse in any of the systems discussed herein. This charge does not include the cost of bringing refuse to the steam generator, but does include the cost of hauling and disposing of furnace residues at land fill dumps. The net solid waste disposal charge or cost is computed from the difference between the total annual costs of operating, the combined-fired plant and the value of, or cost for, electricity generated by a conventional, pulverized-coal plant of identical size built under contemporary capital cost conditions. This cost difference, distributed over the total annual tonnage of refuse fired, and corrected for plant factor, which is 80% for both type plants, is the unit refuse disposal cost, expressed as \$/ton.

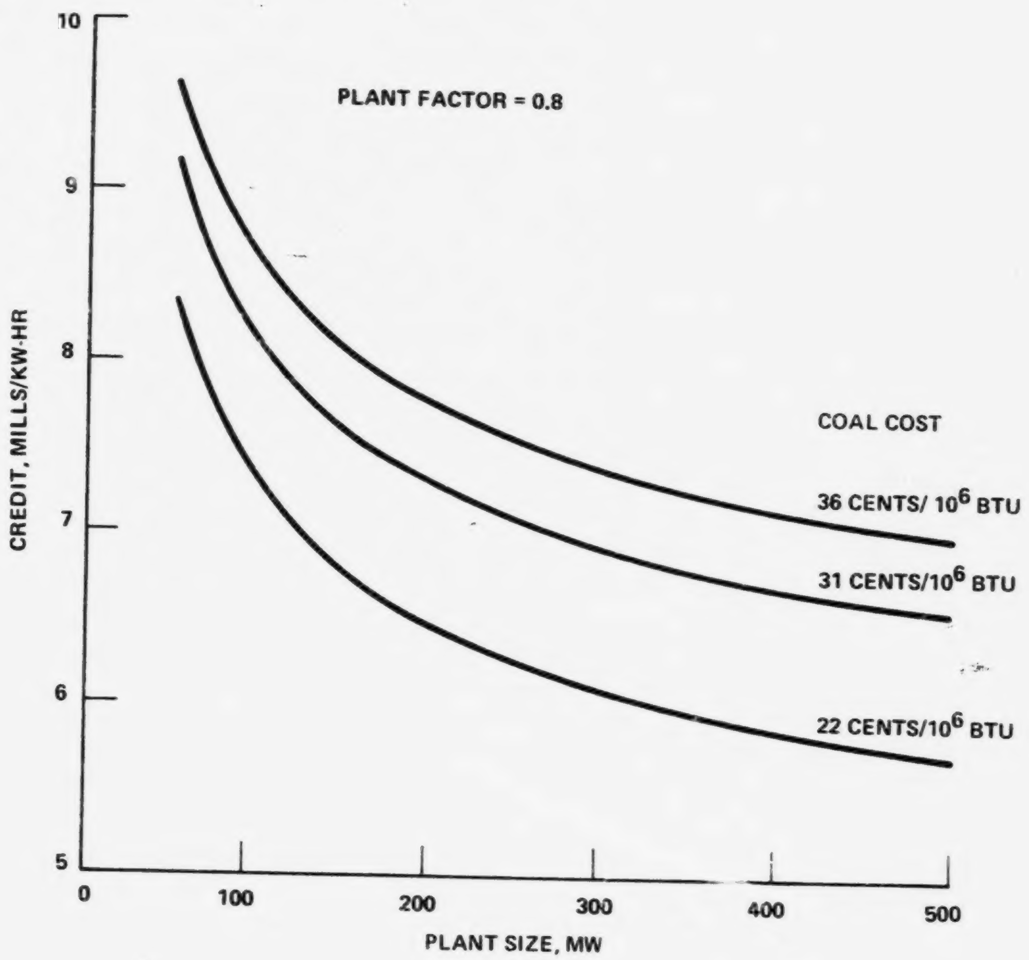


FIGURE C-17. CREDIT FOR THE SALE OF POWER VERSUS PLANT SIZE

TABLE C-14

COST EQUATIONS FOR CONVENTIONAL FOSSIL FUEL POWER PLANT

CAPITAL COSTS

- Land and Land Rights

  $C_{LC} = (0.065\ P_T + 37)\ C_A$

- Structure and Improvements

  $C_{SF} = 5.06 \times 10^4\ P_T^{0.755}$

- Steam Generator

  $C_{SG} = 6.19 \times 10^4\ P_T^{0.914}$

- Boiler Water Treatement

  $C_w = 2.21 \times 10^3\ P_T$

- Pumps

  $C_{PE} = 1.11 \times 10^4\ P_T^{0.73}$

- Turbine-Generator Equipment

  $C_T = 14.04 \times 10^4\ P_T^{0.725}$

  $C_C = 7.36 \times 10^3\ P_T^{0.886}$

  $C_{CE} = 2.17 \times 10^5\ P_T^{0.352}$

- Accessory Electrical Equipment

  $C_E = 4.84 \times 10^4\ P_T^{0.71}$

- Miscellaneous Equipment

  $C_{PCR} = 2.3 \times 10^3\ P_T^{0.86}$

  $C_M = 4.63 \times 10^4\ P_T^{0.24}$

- Piping and Insulation

  $C_P = 5.9 \times 10^3\ P_T^{1.1}$

- Coal Handling

  $C_{CO} = 1.81 \times 10^4\ P_T^{0.738}$

- Residue Handling

  $C_R = 3.66 \times 10^4\ A^{0.858}$

  $A = 4.21 \times 10^{-3}\ W_F$

- Stacks

  $C_S = 141\ W_F$

- Air Pollution Control Equipment

  $C_{IWS} = (1.06 \times 10^{-2} V + 131.6)\ \exp(4.25 \eta_w)$

  $C_{INJ} = 2.75 \times 10^4\ P_T^{0.69}$

  $C_{RH} = 1.14 \times 10^4\ P_T^{0.8}$

- Engineering and Inspection

  $C_{EI} = 1.03 \times 10^5\ P_T^{0.495}$

OPERATING & MAINTENANCE COSTS

- O&M Costs

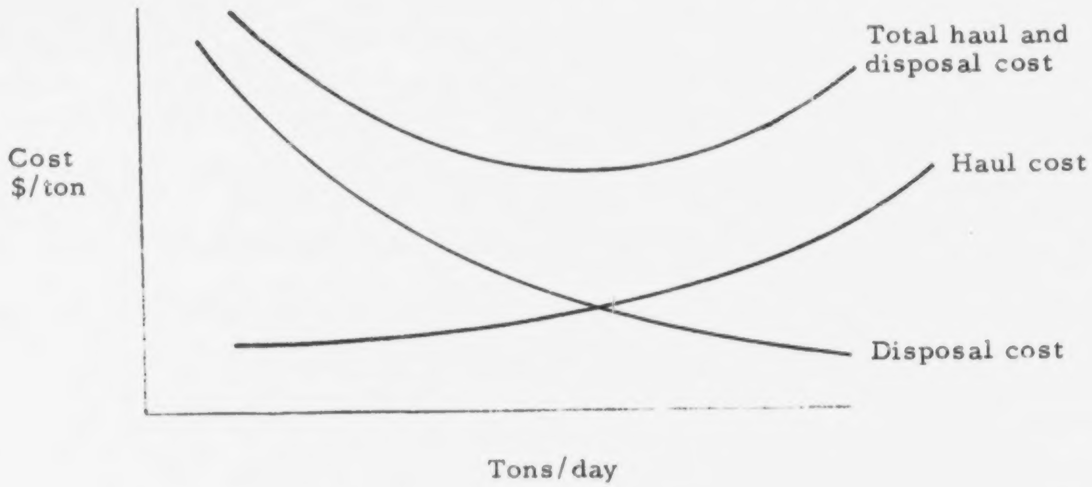
  $C_{OM} = 2.7\ P_T^{-0.225}\ (8760)\ P_T$

- Coal Cost

  $C_{COAL} = 0.73\ W_F H_F C_U L_F$

III. TRANSPORTATION COST MODEL

The transportation cost model permits some additional insights into the total cost of disposal. As a general rule, the economies of scale will indicate that the unit cost of disposal will continue to decrease as the total tonnage increases. However, this waste must come from farther and farther out, thus increasing the haul costs. At some point these additional costs will outweigh the economies of scale as illustrated below:



The transportation cost model computes the cost of hauling waste to the steam generator. In terms of generally accepted solid waste management definitions, this cost embraces the expenses of hauling refuse, in vehicles that are already fully loaded on their routes or have completed collection routines, to the disposal site. Transfer operations, if applicable, are normally included in this cost. The model computes the transportation by multiplying a unit cost (e.g., $/ton-mile) by the haul distance and waste load where the unit cost is a function of vehicle speed. The requirement then is to sum up the products of unit cost, distance, and the correspondingly located waste load over the region of interest. For a large number of closely spaced units, as would be the case for transporting waste from households to a centrally located plant, these products can be considered continuous, thus allowing the summation to be replaced by integration. The equation then for the cost of transportation is:

$$C_{TR} = \frac{\int_R C_r \cdot r \, d w}{\int_R d w}$$

where C_{TR} = transportation cost, \$/ton

C_r = unit transportation cost, \$/ton-mile

r = haul distance, miles

dw = differential waste load

R = region of interest

To evaluate this equation, dw must be determined. If it is assumed that waste would be hauled to a centrally located plant, i.e., the plant is in the center of the hauling area, but not necessarily at the population center, then:

$$dw = W'_R P_d (x, y)\, dx\, dy$$

where: $P_d(x, y)$ = population density as a function of x and y

W'_R = per capita waste load, tons/cap.-day

The population density distribution is not known precisely for the six regional study areas considered in this program. This being the case, a population distribution function must be assumed. A normal (Gaussion) distribution seems reasonable as a first approximation, even though the maximum population density may not be at the center. This is because population is used only to represent the ultimate requirement of waste load and there is a large quantity of commercial wastes in the center of a metropolitan area. With this assumption, the population density can be expressed using the probability distribution equation:

$$P_d (x, y) = \frac{1}{2\pi\sigma_x \sigma_y} \exp \left\{ -\frac{1}{2} \left[\left(\frac{x - \mu_x}{\sigma_x} \right)^2 + \left(\frac{y - \mu_y}{\sigma_y} \right)^2 \right] \right\}$$

where: σ_x = standard deviation in the x direction

σ_y = standard deviation in the y direction

μ_x = mean value of x

μ_y = mean value of y

If it is assumed that $\sigma_y = \sigma_x$, and that T_p is a scale factor of the total population in the area which converts the unit normal distribution to the waste load spatial distribution, then:

$$d\,w = \frac{W'_R\,T_p}{2\pi\sigma^2}\exp\left\{-\frac{1}{2}\left[\frac{(x-\mu_x)^2+(y-\mu_y)^2}{\sigma^2}\right]\right\}dx\,dy$$

where: T_p = total population in the area

The concepts discussed above are shown pictorially in Figure C-18.

To evaluate $P_d\,(x,\ y)$ for any given area, it is necessary to determine σ for that area density by assuming that the total population given for a study area is contained in 99% of the total area under the normal surface. This corresponds to a radius of 3σ and therefore:

$$r = \left(\frac{Tp}{\pi\overline{P}_d}\right)^{0.5} = 3\sigma$$

$$\sigma = \frac{1}{3}\left(\frac{Tp}{\pi\overline{P}_d}\right)^{0.5}$$

where: $\overline{P}_d$ = average population density, cap. /mile^2

The unit transportation cost is a function of vehicle speed which, typically, is also influenced by haul distance. Using data in Reference C-5, an equation was developed to express vehicle speed as a function of haul distance. Using $21.75 per hour as the cost of a 5-ton truck, the unit cost of transportation becomes:

$$C = \frac{0.57}{(x^2+y^2)^{1/2}} + 0.0916$$

Substituting for P_d, dw, σ, and C, the transportation cost equation becomes:

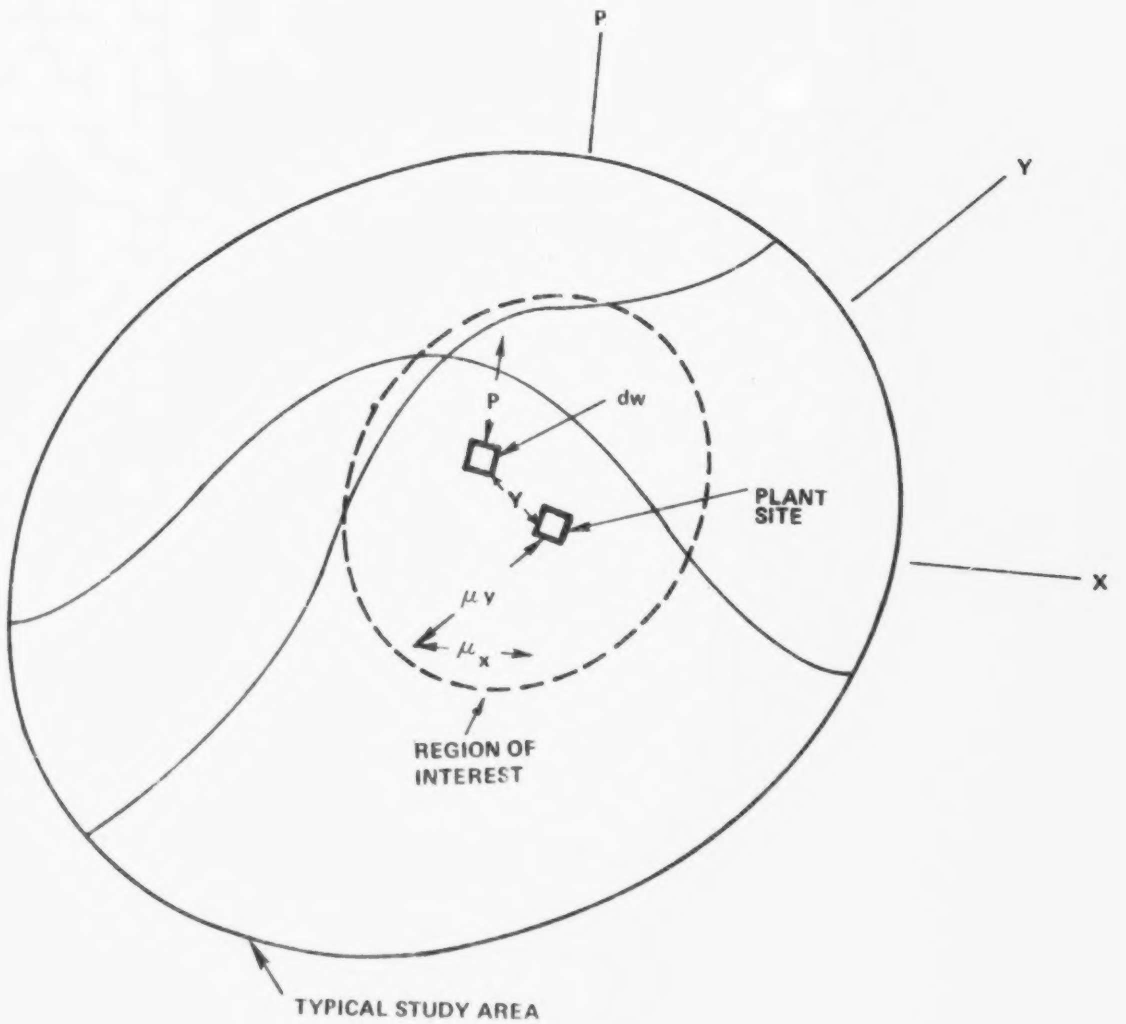

P
Y
X
P
dw
Y
PLANT SITE
μ_y
μ_x
REGION OF INTEREST
TYPICAL STUDY AREA

FIGURE C-18. NORMAL POPULATION DISTRIBUTION IN A TYPICAL STUDY AREA

$$C_{TR} = \frac{\int_{-r}^{+r}\int_{-a}^{+a} (b \exp 1.14\, c) + 0.183\,(x^2 + y^2)^{\frac{1}{2}}\, dx\, dy}{\int_{-r}^{+r}\int_{-a}^{+a} b \exp c\, dx\, dy}$$

where: $a = (r^2 - y^2)^{\frac{1}{2}}$

$b = 4.5\, \overline{P}_d\, W'_R$

$c = \left\{ - \frac{4.5\, \pi\, \overline{P}_d}{T_p} \left[(x - \mu_x)^2 + (y - \mu_y)^2 \right] \right\}$

This is solved by numerical integration for a preselected collection radius and plant location relative to the center of the study area.

The parameters μ_x and μ_y can be chosen to position the plant site at any desired location; i.e., the plant site is located a distance from the center of the area equal to μ_x and μ_y in a rectangular coordinate system.

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APPENDIX D

BIBLIOGRAPHY

1. SUMMARY OF CONTENTS

The following compilations list reasonably current and accessible information sources that deal with subjects falling within the basic scope of the present report. Thus, while the broad fields of steam generation, air pollution, and waste management have been searched, only those publications that clearly relate to refuse-fuel steam systems have been cited. In the case of writings on novel or conceptual schemes for refuse incineration or handling, considerable latitude of selection was observed.

The inclusion of literature dealing primarily with conventional refuse incineration has been avoided, except that which goes to air pollution aspects. The pollutants emanating from burning refuse will obviously be qualitatively similar regardless of whether the furnace is of the heat recovery type or not. An excellent bibliography (544 citations) on conventional refuse incineration and related subjects is contained in Reference 203.

This bibliography has been divided into seven topical groupings. Each is organized alphabetically according to author's name or issuing agency. Because of the contemporary nature of this technology, no publication dating earlier than 1962 has been cited. Particularly where publications of greater technical depth are available on the same subject, citations of news-type articles have generally been avoided. Titles placed in parentheses are translated versions.

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APPENDIX E - GLOSSARY

Air -

Theoretical or stoichiometric - the quantity of air required to oxidize all of the labile constituents in a unit weight of fuel to CO_2 and H_2O.

Excess - the quantity of air in excess of theoretical employed in the combustion process.

Combustion - theoretical plus excess air. The terms primary-, secondary-, and tertiary-air are also used. These terms, derived from pulverized coal firing, relate to the air-flow arrangements up to and with respect to the burner.

Underfire - the combustion air introduced under a grate to promote burning within the fuel bed.

Overfire - the combustion air introduced over a grate to promote combustion of the gases rising from the fuel bed.

Air Heater - A device for transferring some of the residual heat in the exhaust flue gas to the intake air passing into the furnace to support combustion. The recuperative and regenerative types are the best known generic forms.

Annualization - The annual apportionment required to recover all capital related costs, such as interest, amortization, insurance, and taxes.

APC - Air pollution control.

Bag House - An air pollution control device consisting of a system of fabric filter envelopes through which flue gas is passed to remove dust.

Boiler Surface - That portion of the boiler working-fluid circuitry in which water undergoes change of state; i. e., boiling occurs.

Calorific Value - See Heating Value.

CAMP - Continuous Air Monitoring Program.

Capital Recovery Factor - The annual percentage that is required to amortize the capital debt at some given rate of return for a definite time period.

Clinker - A solidified slag deposit found in a boiler.

Convection Section - That portion of the boiler in which the exchange of heat through boiler surfaces occurs directly between the flue gas and the working fluid. Thus, those sections which are obstructed from the flame and do not undergo radiant heat transfer.

Critical Pressure - A characteristic partial pressure of a substance at which liquefaction can occur when the substance is at critical temperature.

Critical Temperature - A characteristic temperature of a substance above which liquefaction cannot occur, regardless of its partial pressure. The substance is then said to be a gas rather than a vapor.

Demister - A device for removing liquid droplets entrained in flue gases.

Disposal Cost - In the present report, this is an inside battery limits cost term that includes all plant costs for reducing refuse to an inert residue and effecting the ultimate disposal of the latter. Refuse transportation costs (q. v.) and power transmission are necessarily excluded from disposal cost.

Downcomer - A member of a steam circuit, usually unheated, which permits the working fluid to flow as a liquid, usually saturated, down to a distribution point from which it can then rise through boiler tubes within the furnace.

Duty - The energy content of the steam produced per unit time by a boiler. Usually expressed as 10^9 Btu/hr.

Economizer - The first stage of the boiler where the working fluid is heated by exiting flue gas. Typically, feed water is fed back through the economizer and then passed to the primary boiler steam circuits.

Efficiency (Combined Steam Generator) - The percent of the input fuel energy transferred to the output working fluid.

Electrostatic Precipitator - An air pollution device consisting of an array of electrodes through which the flue gas flows. The high voltage cathodes operate at corona condition and induce some ionization of the flue gas. Collisions between negative ions and particles charge the latter with surface electrons and cause migration to the grounded anodes. There discharge occurs and the collected dust can be mechanically dislodged into hoppers.

Enthalpy - The heat content of a system; usually expressed as the sum of the internal energy (sensible and latent heats) and the work content implicit in the pressure-volume condition.

Feedwater Heater - A heat exchange system for heating the working fluid recovered in the condenser to desired economizer inlet conditions. The energy for this process is often supplied by steam tapped from the turbine.

Fireside - Loosely, that portion of boiler heat exchange structures exposed to hot combustion gases (as opposed to steam side).

Forced Circulation - Boiler circuitry in which movement of the working fluid from the drum through downcomers, up boiler tubes, and back to the steam drum is promoted by pumps.

Fossil Fuel - Any material capable of supporting combustion that has been formed by the long-term effects of subterranean environments on ancient vegetable deposits. Included are such fuels as coal (anthracitic, bituminous, lignitic), oil, natural gas, and by-products thereof, as well as certain less fossilized materials.

Fuel Value - See Heating Value.

Grate - Device for supporting coarse fuels stoked into furnaces. Agitating grates are inclined, the steps of which can move in either a rolling or reciprocating manner. Travelling grates are endless-belt conveyors (non-agitating) and are usually horizontal. Retainer grates are stationary devices situated in the hopper area to catch burning fall-out from material fired in suspension.

Heat Capacity - The quantity of heat required to increase the temperature of a unit weight of substance 1 degree in the absence of frictional and change of state processes. In the English system, the Btu is defined as the quantity of heat required to cause a temperature rise of 1°F in 1 lb of water from 39.1°F (maximum density temperature).

Heat Rate (Net Plant) - The heat from fuel that must be supplied to produce a unit of power. This term is usually expressed as Btu/kw-hr.

Heating (or Heat Value) - The thermal energy released per unit weight of fuel (Btu/lb or cal/g) undergoing combustion. In the U.S., the higher heating value (HHV) is used. This corresponds with calorimetric measurement, in that water vapor formed during combustion is considered to undergo condensation. In Europe, the lower heating value (LHV) is commonly used. This term, usually calculated from the calorimetric value or HHV, requires that the water formed by the oxidation of bound hydrogen in the fuel does not undergo condensation after the combustion process has occurred.

Liquid (or Wet) Scrubber - Any air pollution control device that brings the flue gas into intimate contact with a liquid phase to effect contaminant removal. The process can proceed by the acquisition of liquid on particles in the flue gas to render them susceptible to subsequent removal in mechanical collectors or by the entrapment of solids within or the solution of gases into the liquid phase.

LMA - Large Metropolitan Area.

Mechanical Dust Collector - Any inertial air pollution control device which traps out particulates by centrifugal force. The latter effect is imparted by the gas stream itself, which is made to flow in a cyclonic, or related, manner within the collector.

Nameplate Rating - The nominal power capacity of a turboelectric system specified in the construction contract for normal operating conditions. Because of design margins, actual capacity is usually greater.

Net Disposal Cost - See Disposal Cost.

Net Total Disposal Cost - The sum of disposal and transportation costs.

NASN - National Air Sampling Network.

Natural Circulation - Boiler circuitry in which movement of the working fluid from the drum through downcomers, up boiler tubes, and back to the steam drum is promoted by convection within the liquid phase.

Once Through - Boiler circuitry in which the working fluid does not circulate as a liquid via a drum, but is completely volatilized in its first pass through the radiant section of the boiler.

Pendant Section - A continuous tube run in a panel-like arrangement, the inlet and outlet ends of which are supported by headers. The section thus hangs from the latter.

Plant Factor - The ratio of the average electrical load to the rated capacity for a given time period.

Platen Section - A continuous tube arrangement, the vertical members of which are set very closely together. Each panel-like section is placed in-line with respect to gas flow and 9 to 12-in. apart from other platen sections arranged in parallel. The purpose of a platen superheater is to drop the temperature of the flue gas so that slagging and fouling on more closely grouped tube banks downstream will be minimized.

Radiant Section - That portion of the boiler in which the transfer of heat to the working fluid can occur by the absorption of radiant energy emitted by the flame.

Rankine Cycle - A hypothetical cycle of a steam generator in which all heat transfers take place at constant pressure and in which expansion and compression effects are produced adiabatically.

Reheat - A process wherein turbine exhaust steam, usually from the first stage, is passed back through isolated heat exchange surfaces (reheaters) in the furnace to regain some of the energy transferred to the turbine. The reheated steam is then introduced at a lower stage of the turbine.

Retrofit - An operation wherein an existing device or system is modified through the addition of new components so as to make it function in an improved or different manner.

Saturation - When a liquid and its vapor are in equilibrium, each phase is said to be saturated. For every temperature below the critical temperature, there is a discrete pressure at which saturation (equilibrium) can exist.

Sensible Heat - Heat which has been absorbed to produce a change in temperature due to the heat capacity of the substance, as contrasted to energy (latent heat) contributing to change of state processes.

Shot Cleaning - A process wherein large steel shot (1/4- to 1/2-in. dia.) is distributed, usually by gravity, down through convective passes to dislodge ash accumulations. The shot is recovered and reused.

Slag - Molten ash.

Slag-Tap (or Slagging) Furnace - See Wet Bottom Furnace.

SMSA - Standard Metropolitan Statistical Area.

Soot Blower - A device situated in various portions of a boiler for directing jets of steam or air onto tube banks to dislodge ash accumulations.

Specific Heat - See Heat Capacity.

Spreader-Stoker - A firing arrangement wherein a coarsely divided fuel is fed into the furnace by a suitable conveyance system and is blown upward into the furnace by air jets. The falling, ignited fuel then falls onto a horizontal grate to be burnt out and disposed of. The grate typically used is of the travelling (endless belt) type.

Steamside - That portion of the heat exchange surfaces which are in contact with the working fluid, regardless of which phase is present.

Superheat - A furnace process wherein saturated steam from the boiler is increased in temperature, enthalpy, and specific volume to required outlet conditions. Superheater surfaces may be located in both the radiant and convective zones of the steam generator. By superheating steam, a thermodynamic gain in the Rankine cycle results.

Suspension Firing - The process in which a solid fuel, usually of reduced particle size, is injected into the mid-zone of the furnace so that it will tend to burn out before settling.

Tipping - The unloading of refuse from a collection vehicle.

Topsize - The specification for maximum particle length in any dimension for coarse output from a hammermill or related grinding device.

Transportation Cost - The cost, exclusive of collection costs, of transporting refuse, once trucks are loaded, to the disposal point.

TÜV - Technische Überwachungs Verein. A German organization involved in the qualification and acceptance testing of steam generators and various other hardware.

Tuyere - A furnace wall section containing a network of air nozzles. In the present context, a system for delivering side-fire air to grates.

Venturi Scrubber - A wet scrubber in which the flue gas is accelerated through a restriction or venturi to cause aerosolization of a scrubber liquid injected into the venturi throat. Impaction of scrubber droplets with dust particles renders the latter more susceptible to mechanical collection.

Wet Bottom Furnace - By virtue of its design and the fusion temperature of the fuel used, a furnace which collects molten ash (slag) in its bottom. The slag is periodically or continuously removed for quenching (solidification in water) through a suitable orifice (slag tap).